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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Services for the Period 2015-2017 (U 39 G).	A.13-12-012 (Filed December 19, 2013)
And Related Matter.	I.14-06-016

OFFICE OF RATEPAYER ADVOCATES OPENING BRIEF

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1 OVERVIEW

On December 19, 2013, Pacific Gas and Electric Company (PG&E) filed this Gas Transmission and Storage (GT&S) Rate Case Application seeking authority to increase its gas transmission and storage base revenue requirements by $572 million for the Test Year, 2015.[1] PG&E also asked for additional increases in 2016 and 2017 for a 3-year cumulative revenue increase of approximately $2 billion dollars.[2]

1.1 Legal Issues (e.g., Burden of Proof, Commission Jurisdiction)

The term burden of proof is often used to describe multiple components of the obligations on parties to present evidence, the required level of a showing, and the topics on which a showing is required. As noted by Witkin, "The term 'burden of proof' is often used loosely in two senses: (1) the secondary meaning of the burden of initially producing or going forward with the evidence; and (2) the primary meaning of the burden of proving the issues of the case."[3]

Applicant PG&E bears the burden of proof in this proceeding. The Commission is charged with the responsibility of ensuring that all rates demanded or received by a public utility are just and reasonable; "no public utility shall change any rate... except upon a showing before the Commission, and a finding by the Commission that the new rate is justified."[4] Thus, in ratemaking applications, the burden of proof is on the applicant utility.[5]

The Commission has recently reaffirmed in Decision (D.) 14-12-025, adopting the new General Rate Case (GRC) framework, that the standard for the degree of proof in General Rate Cases is by a preponderance of the evidence, after the Commission had employed the clear and convicting standard for years. The preponderance of the evidence standard, prevalent in civil

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[1] *See* ORA-37 (Skinner/ORA), p. 1 and PG&E-01 (Krannich/PG&E/Krannich), p. 3-1. There is a slight difference (PG&E's number of $555 million is approximately $17 million lower in 2015) between ORA's and PG&E's calculations. ORA's calculations were correct, *see* 28 RT 3906:27 – 3908:4.

[2] *See* ORA-37 (Skinner/ORA), p. 1.

[3] Witkin, California Evidence 5th Edition (2012), Burden of Proof § 1.

[4] Public Utilities Code §§ 451, 454.

[5] *See, e.g,* Application of Pacific Gas and Electric Company (2000) D.00-02-046, mimeo, p. 36, 2000 Cal. PUC LEXIS 239.

proceedings, including administrative proceedings, is generally viewed to require that the evidence presented on one side of an issue is more persuasive than that in opposition.[6] The preponderance of the evidence standard does not relieve applicant PG&E of the burden of initially producing and providing evidence that is actually persuasive, and other parties are not required to offer evidence if PG&E fails to meet its initial burden.

1.2 **Policy Issues**

In the wake of the San Bruno incident in September 2015, PG&E has attempted to dramatically overhaul its efforts to maintain a safe gas distribution, transmission and storage system. PG&E's request for a historically large revenue requirement increase in this GT&S proceeding reflects PG&E's increased emphasis on providing safe transmission service. ORA's recommended revenue requirement figure, if adopted, would grant 58% of this increase, a figure similar to the 59% increase adopted by the Commission itself in its decision on the 2014 PG&E GRC.[7] ORA's policy governing its review and forecast of PG&E's safety-related costs in this proceeding has generally accepted the need and accompanying costs for assessing the scope of safety issues that PG&E's past practices might have overlooked, and often accepted the level and scope of costs PG&E forecasts to address such particular problems, with recommended reductions often due to the increased costs included in this rate case period related to the consequences of PG&E's deferred maintenance or other negligent actions regarding safety. ORA's understanding of the substance of safety guidelines and related statutes and regulations has grown over the past few years.

Despite recommending a revenue requirement that would grant PG&E such a large percentage increase, ORA still recommends the exclusion of approximately $200 million from PG&E's 2015 Test Year request, per the arguments above arguing for increased shareholder assumption of safety costs, as well more traditional recommended reductions regarding items such as the level of unit costs and scope of proposed PG&E work, for example around Vintage Pipe Replacement (VIPER) or pressure testing. ORA believes its recommended reductions to

[6] California Administrative Hearing Practice 2nd Ed. (CEB) § 7.51.
[7] ORA notes that throughout this brief, the lack of a specific disallowance or recommendation does not constitute agreement with the reasonable of PG&E's forecasts.

PG&E's proposed revenue requirement to be recovered from ratepayers are fair and reasonable, particularly given ORA's acceptance of the majority of the increase requested by PG&E. ORA's proposed revenue requirement similarly provides PG&E with a reasonable opportunity to recover its costs and rate of return under the current circumstances.

ORA generally does not recommend any changes to the traditional rate case principles governing the discretion of PG&E to utilize the revenue requirement adopted in this proceeding in a reasonable fashion to address its current priorities. Despite PG&E's recent transgressions with respect to safety, and with the exceptions for the costs associated with activates as noted above, and the expectation of increased safety oversight from appropriate government agencies such as SED and PHMSA, ORA accepts that PG&E still generally requires the discretion to utilize its revenue requirement adopted in this proceeding as PG&E best sees fit in order that PG&E can provide safe and reliable gas transmission service during the test year and rate case period.

PG&E's spending discretion, however, is not unlimited and comes with the condition that PG&E is worthy of trust to reprioritize in good faith the resources collected from ratepayers and approved by the Commission in this proceeding for PG&E to provide safe and reliable gas transmission and storage service at just and reasonable rates. PG&E's well-publicized violations of the Commission's ex parte rules in this current proceeding were addressed in a separate phase, and the Commission imposed fines and limitations on its allowed ex parte activities onto PG&E.[8] This proceeding is presently considering the question of damages associated with the delays to this proceeding caused by the ex parte violations, and will consider the impact of the recently adopted decision in the Pipeline OII in a subsequent phase of this proceeding. But PG&E's serious breach of Commission Rules and basic protocols of fairness and due process also calls into question the honesty the Commission requires of PG&E to meet its safety obligations and in its cost showings related to safety. ORA is greatly dismayed that as PG&E was attempting to make efforts to improve its safety culture, its management was flagrantly flouting fundamental Commission rules regarding due process with respect to the disposition of this proceeding and numerous other Commission proceedings regarding safety and safety costs of its gas distribution, transmission and storage systems.

[8] D.14-11-041.

PG&E also pushes past the edges of reasonable budgetary discretion in offering forecasts apparently not on a bottoms-up, project by project process dependent upon the actual status of and spending related to such projects in the Test Year, but assuming that any projects cancelled or postponed until after the Test Year are apparently automatically replaced by other projects at the same level of initially proposed costs. PG&E's VIPER program, hydrotest program, corrosion control,[9] and spending levels on general gas operations exhibit strong indications of a "top-down" approach to budgeting rather than the "bottoms up" approach PG&E claims it is using to calculate a reasonable forecast. PG&E has the discretion to spend its revenue requirement on activities that differ from those they specifically include in their rate case applications, but they do not have the discretion to base its revenue requirement on the costs of projects not expected to be completed that are apparently mere placeholders for other projects not subject to review and scrutiny in this rate proceeding. PG&E also is moving specific projects, where PG&E improperly conducted past work, into categories where ratepayers would pay for them, such as the remedial work to bring Line 300B into compliance with long-standing federal regulations regarding maximum allowable operating pressures.[10, 11]

PG&E's proposed risk assessment model to justify the projects it proposes in this proceeding is not yet sufficiently robust to be relied upon by the Commission to solely determine the projects and appropriate level of costs approved in this proceeding and included in rate base. PG&E's use of a model that intermingles business risks to PG&E with safety risks to the public and to PG&E, based on internal calculations of such risks, and does not provide measures of risk reduction per costs proposed, does not prove sufficient rigor or objectivity for Commission adoption.

Ultimately, PG&E has the responsibility of maintaining a safe and reliable transmission system independent of the particular level of revenue requirement the Commission adopts in this proceeding or the particular method the Commission uses to determine that level of revenue requirement. Even if the majority of costs and cost increases in this proceeding are related to

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[9] For example, PG&E's claims of spending approximately $79 million of shareholder money on corrosion in Ex. PG&E-1 p. 7-2 (Armato/PG&E),, are unsubstantiated as to the work that shareholders are actually paying, rather than ratepayers.

[10] Ex. ORA-156 (PG&E Response to ORA DR-148 Q1 and Attachment 1),

[11] 17 RT 1647 – 1651 generally.

safety, by retaining the discretion to reprioritize spending to programs not specified in this application in conjunction with the determination of its revenue requirement, PG&E assumes the responsibility to provide safe, reliable service to its customers at just and reasonable rates, and for the costs of whatever activities it deems necessary to meet these requirements. Even with all the increased safety implications, this is still a rate proceeding primarily evaluating a forecast of PG&E's 2015 revenue requirement, as well as the conditions and terms of its various gas transmission and storage service offerings to varied customer classes.

1.3 **Summary of Revenue Requirement Recommendations**

Prior to accounting for stipulations, ORA recommended a 2015 TY revenue requirement increase of $329 million and a cumulative increase of $1.2 billion over the three-year test period.[12], [13] While ORA has not yet completed a complete rerun of the Results of Operations model to reflect the updated recommendations with the stipulations and any changes in the brief, ORA's estimate for the 2015 TY revenue requirement would have only a moderate increase over its recommendations in direct testimony leading to a 2015 TY revenue requirement of $1,044 million.[14]

Unless specified otherwise, "the lack of a specific ORA disallowance or forecast in some program areas should not be taken to constitute agreement with PG&E's proposals."[15] In many cases other parties offer recommended reductions that complement or augment ORA's recommendations.

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[12] *See* ORA-37 (Skinner/ORA), p. 7.

[13] *See* ORA-37 (Skinner/ORA), p. 8.

[14] *See* Joint Stipulation-2 (PG&E-ORA/Stipulation), p. 1; and ORA-37 (Skinner/ORA), p. 1.

[15] *See* ORA-40 (Karle/ORA), p. 2.

In summary, ORA makes the following revenue requirement recommendations:[16]

General Policy and Core Gas Issues
Consistent with previous decisions, PG&E shareholders should continue to bear cost-responsibility for hydrotesting pipelines installed after 1956. The Commission should reject PG&E's arguments that shareholders bear responsibility for pipelines installed only after General Order 112 came into effect, in 1961.

Valve Automation and Inoperable Valves
• ORA does not oppose PG&E's forecast expenditures of $52.502 million for valve automation in the Transmission Pipe Integrity and Emergency Response Programs category. • For inoperable and hard to reach valves, ORA's forecast is $4.0 million, which is approximately $3 million lower than PG&E's forecast of $7.1 million. • ORA's adjustments are recommended because valves reaching the stage of inoperability should be repaired as part of routine maintenance.

In-Line Inspection
• ORA does not oppose PG&E's expense forecast of $31.5 million for traditional and non-traditional ILI, casings, or traditional and non-traditional direct examination and repair. • ORA does not oppose PG&E's capital forecast of $74.3 million for traditional and non-traditional ILI.

Hydrotesting and Vintage Pipeline Replacement
• For capital expenditures on Vintage Pipeline Replacement, ORA's forecast in 2015 is $110.0 million as compared to PG&E's forecast of $193.8 million. • For expenses on Hydrotesting, ORA's 2015 forecast is $91.7 million, compared to PG&E's forecast of $179.2 million. • ORA's adjustments are based primarily on differences in unit cost forecasts based on actual costs from PG&E's PSEP Program.

[16] *See* ORA-37 (Skinner/ORA), pp. 13-22.

Direct Assessment

- For the expenses addressed in this exhibit, ORA forecasts expenses of $23.0 million compared to PG&E's forecast of $46.5 million in 2015.
- ORA does not oppose PG&E's request for $2.9 million for Stress Corrosion Cracking Direct Assessment.
- ORA's primary adjustments/recommendations are associated with distribution integrity management programs PG&E has already received funding in the 2014 GRC and the ratio of digs per project.

Integrity Management Enhancement and Public Awareness

- For the 2015 expense forecast requested by PG&E, ORA recommends a public awareness forecast of $2.6 million as compared to PG&E's forecast of $4.3 million.
- ORA does not oppose PG&E's 2015 forecasts for root cause analysis of $1.1 million and risk analysis process improvement of $6.2 million.

Class Location, Shallow Pipe, and Water Crossing

- ORA's expense forecast for class location is $3.9 million compared to PG&E's forecast of $6.4 million in 2015.
- ORA's capital expenditure forecast for class location is $10.8 million in 2015 compared to PG&E's forecast of $17.1 million.
- ORA does not oppose PG&E's 2015 expense forecasts of $1.4 million for Water and Levee Crossing or the $3.1 million for Shallow Pipe programs.
- ORA does not oppose PG&E's capital expenditure forecasts for 2013-2015 for Water and Levee Crossing or Shallow Pipe programs. PG&E's Water and Levee Crossing forecasts for 2013 through 2015 are $1.7, $0, and $13.4 million respectively. PG&E's Shallow Pipe forecasts are $0, $2.0, and $21.6 million in 2013, 2014, and 2015.
- ORA's primary adjustment is to the unit costs associated with hydrotesting and a slower pace for replacement projects.

Storage and Program Management Office
ORA recommends adoption of Joint Stipulation-3 between PG&E and ORA. • ORA does not oppose PG&E's forecast of $0.6 million in expenses and $12.5 million in capital expenditures for the Storage Asset Family. • ORA does not oppose PG&E's forecast of $6.3 million in expenses and $6.4 million in capital expenditures for the Program Management Office.

Facilities
• For Engineering Critical Assessment (ECA) Phase 1, Phase 2, and hydrostatic testing, ORA recommends adopting the PG&E-ORA Joint Stipulation-5. The stipulation recommends a 2015 expense forecast of $3.0 million for hydrostatic testing and $12.2 million for ECA Phase 1 and 2. • For Critical Documents, ORA recommends a forecast of $0, instead of PG&E's forecast of $11.6 million. • ORA recommends $0.6 million for Gas Quality Practice Assessment, which is approximately $1.5 million lower than PG&E's $2.1 million forecast. • For Routine Expense Spending, ORA recommends a forecast of $12.5 million rather than PG&E's forecast of $16.8 million. • For the retrofit of the Hinkley Compressor Units in 2016 and 2017, the Commission should reject PG&E's proposal and provide no ratepayer funding. • ORA recommends no ratepayer funding for Biomethane Interconnections, compared to PG&E's request for $4.8 million. • For Biomethane Interconnections, PG&E's proposed tariffs clearly require the party who is applying to provide biomethane bears the cost of interconnection, and PG&E's comments in the biomethane proceeding explained PG&E was going to correct its GT&S filing.

Corrosion Control
• For mitigating Contacted Casings, ORA recommends a cost cap of $4.9 million in expense, compared to PG&E's forecast of $48.5 million in 2015. ORA's cost cap provides ratepayer funding equal to 2013 spending plus the additional 6 casings PG&E expects to find contacted in 2015. • For capital expenditures on Contacted Casings, ORA recommends a cost cap of $1.9 million, which is equal to PG&E's 2013 capital expenditures plus the funding equal to the 1.33 additional capitalized casings PG&E expects to find in 2015. PG&E's 2015 forecast is $21.1 million. • Direct Current mitigation is forecast by PG&E to have $2.6 million in expense for 2015. ORA recommends $2.0 million. ORA's capital expenditure forecast is $0.4 million compared to PG&E's $0.8 million forecast. • Alternating Current mitigation is forecast by ORA to have $5.8 million in capital expenditures compared to PG&E's 2015 forecast of $10.3 million. • For Atmospheric Corrosion, ORA's 2015 expense forecast is $16.1 million compared to PG&E's $20.4 million forecast. • ORA's adjustments and cost caps are primarily based on PG&E's deferred maintenance in meeting long-standing federal regulations. ORA in these cases provides funding for investigation and to maintain PG&E's 2013 work levels plus new areas of work anticipated for 2015.

Gas Transmission Operations and Maintenance
• ORA does not oppose PG&E's forecast expenses on the Stanpac Pipeline System, Mark and Locate, Operate Transmission Pipeline, Right-of-Way Support, Station Preventative and Corrective Maintenance, Station Projects, Permits and Fees Project O&M. • ORA recommends a Leak Management forecast of $4.0 million as compared to PG&E's forecast of $6.1 million. • For Pipeline Patrol, ORA recommends a forecast of $4.2 million as compared to PG&E's forecast of $8.6 million. • For Pipeline Maintenance and Repair, ORA recommends a forecast of $4.4 million as compared to PG&E's $11.2 million forecast. • For Pipeline Projects, ORA recommends a forecast of $8.8 million as compared to PG&E's $30.6 million forecast.

Program Management Office
ORA recommends adoption of Joint Stipulation-3, which does not oppose PG&E's forecasts for the Program Management Office.

Gas Operations
ORA recommends adoption of Joint Stipulation-3, where PG&E accepts ORA's forecasts for TY 2015 of $18.241 million for Compressor Fuel and Power and $3.088 million for GHG emissions. • For the 2015 expense forecast, ORA recommends a forecast of $46.1 million compared to PG&E's forecast of $47.7 million. • For 2015 forecasts of capital expenditures, ORA recommends using recorded values for 2013 of $0.7 million, a 2014 forecast of $16.8 million, and a 2015 forecast of $15.1 million. This compares to PG&E's forecasts of $53.8 million, $28.0 million, and $79.5 million respectively. • ORA does not oppose PG&E's Normal Operating Pressure and Overpressure Protection policies, but recommends a forecast of $2.3 million for 2015 capital expenditures as compared to PG&E's $10.9 million forecast. • ORA recommends denying PG&E's request to equalize the Redwood and Baja rates for Core and Noncore customers, and instead retaining the traditional cost-differentiated rate design. • ORA supports the proposal to maintain the existing traditional Gas Accord cost allocation methodologies for its backbone transmission, local transmission, gas storage facilities, and transmission-level customer access charges. • ORA recommends denying PG&E's proposal to allocate additional storage capacity to load balancing for injection and withdrawal. • ORA agrees with PG&E that regardless of how the Commission decides to address PG&E's proposal for 100% full balancing account treatment of revenues, core customers should not be allocated any over- or under-collection of noncore revenues. • ORA's capital expenditure forecast differences with PG&E are driven largely by New Capacity Project forecast differences.

Information Technology
ORA recommends adoption of Joint Stipulation-4, where PG&E, ORA, and TURN recommend a 2015 expense forecast of $14.7 million and a capital forecast of $22.5 million. • ORA recommends its capital forecast for 2013 of $5.6 million, based on recorded data as compared to PG&E's forecast of $10.3 million. • ORA recommends its 2014 capital forecast of $12.9 million, rather than PG&E's forecast of $15 million.

Other GT&S Support Plans
ORA recommends adoption of Joint Stipulation-3, where PG&E accepts ORA's capital forecast for Tools and Equipment for 2015. • For Environmental Operations expenses, ORA recommends a 2015 forecast of $6.5 million compared to PG&E's request of $11.1 million. • ORA does not oppose PG&E's 2015 forecasts for Support Costs ($4.6 million million), Habitat and Species Protection ($0.2 million), Hazardous Waste Disposal and Transportation ($0.2 million), Research and Development ($2.2 million), or Customer Access Charge Costs ($1.9 million). • For capital expenditures, ORA recommends a forecast of $11.6 million in 2013, $18.4 million in 2014, and $13.2 million in 2015. This compares to PG&E's forecasts of $9.1 million, $24.4 million, and $13.5 million in 2013-2015. • For Tools and Equipment expenditures, ORA recommends a forecast of $8.9 million in 2013, and $8.9 million in 2014. This compares to PG&E's forecasts of $14.2 million in 2013, and $12.7 million in 2014.

Plant, Depreciation Expense and Reserve, and Rate Base
ORA recommends adoption of Joint Stipulation-1, which establishes $88.3 million in annual depreciation accurals and a 2.15% composite depreciation rate.

Post-Test Year Ratemaking
For Post-Test Year Ratemaking (PTYR) proposals for 2016 and 2017, ORA recommends adoption of Joint Stipulation-3. • ORA also recommends a 3rd PTY, extending the GT&S through 2018.

2 SAFETY AND RISK MANAGEMENT ISSUES

2.1.1 Procedural Background

2.1.2 The Commission Cannot Rely Solely on PG&E's Proposed Risk Assessment To Justify the Reasonableness of PG&E's Proposed Capital Investments in this Proceeding

2.1.2.1 Commission Guidance in D.14-08-032 and D.14-12-025

D.14-08-032 found with respect to PG&E's 2014 GRC filing inlcuding a risk assessment that it should ideally contain a measure of risk reduction per dollar spent, acould consider the principle of ALARP, and still have a cost/benefit analysis. Cycla and Liberty have useful comments, but where Commission interpreted issues they discussed, Commission's interpretation controls over Cycla and Liberty. Because Cycla Liberty concluded that the prior risk showing was not an assessment, and does not specifically review the current filing, PG&E arguments that these analysts would have found this risk analysis to be a risk assessment are speculative and hearsay, and the Commission should give little, if any weight to such an argument. ORA also disagrees that Cycla and Liberty's analysis would have concluded that this risk analysis met the expectations.

In D.14-12-025, the Commission adopted a new framework, with two separate phases to allow for proper and full consideration of risk-based decision-making: the Safety Model Assessment Proceeding (S-MAP) to evaluate utility models, and the Risk Assessment and Mitigation Phase (RAMP) to allow parties the "opportunity to understand the analysis, data and assumptions underlying the utility's presentation and to present a response to the utility's presentation" including workshops, a SED report and other parties to provide a report.[17] The next step in this new framework is expected to begin on May 1, 2015 with the utilities' new S-MAP filings.

2.1.2.2 The Risk Assessment Is Not Sufficiently Robust To Support PG&E's Request

PG&E determined the proposed capital investments included in its application strictly on the basis of its "risk assessment" model, which has no explicit references to costs or measure of

[17] *See* Decision 14-12-025, pp. 29-30, and 38.

risk reduction tied to cost,[18] and without any separate cost-benefit analysis.[19] PG&E's current risk assessment is not yet ready to be relied upon exclusively, and there is no guarantee that any risk assessment will ever be found to be so robust in the processes set forth in D.14-12-025In order for a utility methodology to qualify as a "risk assessment" to be considered to be relied upon solely as the basis for determining whether or not a capital investment is just and reasonable in a GRC, it must at the very least quantify risk reduction per dollar spent. Indeed, without a connection to costs, PG&E's proposal is more accurately described as a "risk analysis" rather than a "risk assessment" because its comparisons of relative risk scores cannot be translated to the dollars spent on those projects. An accurate assessment of risks cannot be calculated by the dimensionless values PG&E's employs, particularly in the context of a GRC which is for the purpose of estimating costs. This absence of costs is particularly striking because PG&E assesses "risk" not from a public safety standpoint but from its own corporate perspective, and over at least the past decade has utilized internal risk analyses that factored costs and contained similar elements to the risk analysis submitted in this proceeding.

PG&E has stated its current risk assessment process began in 2011 and will continue to mature.[20] However, as clearly demonstrated by parties in this proceeding, including ORA, and by the Commission's consultants on PG&E's General Rate Case (GRC), PG&E's risk assessment process falls far short of the Commission's and public's expectations. At some future point through the new process to reform the General Rate Case (GRC) in R.13-11-006, PG&E's models and process may be sufficiently developed to serve as the basis for developing programs in rate cases.[21] In D.14-12-025, the Commission adopted a new framework, with two

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[18] Ex. PG&E-01 (Soto/PG&E), p. 2-5. PG&E states: "In putting forth this forecast, we are also mindful of our customers' limited ability to absorb increased gas transmission and storage rates. We have proposed this scope, pace and trajectory of work only after a thorough analysis of the threats and risks posed to the pipeline assets and after considering potential alternatives … We believe this forecast is the right balance of expenditures and risk reduction for PG&E, our customers and other stakeholders. If the Commission provides fewer reveneus than proposed, however, the trajectory of risk-reduction will be slower, resulting in a higher level of risk over a longer period of time. In that event, PG&E would revisit its prioritization of work across the risk mitigation programs to ensure we mitigate higher risks first."

[19] 15 RT 1336:6-23. (PG&E/White).

[20] Ex. PG&E-01, p. 2-3. (PG&E Prepared Testimony).

[21] *See* Order Instituting Rulemaking 13-11-006. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M081/K856/81856126.PDF

separate phases to allow for proper and full consideration of risk-based decision-making: the Safety Model Assessment Proceeding (S-MAP) to evaluate utility models, and the Risk Assessment and Mitigation Phase (RAMP) to allow parties the "opportunity to understand the analysis, data and assumptions underlying the utility's presentation and to present a response to the utility's presentation" including workshops, a SED report and other parties to provide a report.[22] However, PG&E is nowhere near that point for the current Application.

2.1.2.2.1 Dimensionless Values Which Change Dramatically Over Time

PG&E admitted in rebuttal testimony:[23]

> Q 17. Most if not all of the concerns expressed by the Parties about PG&E's risk management process involve alleged failures to perform certain steps or analyses in its risk management processes. Has the Commission adopted a framework for utilities to use to present their rate cases based on risks?
>
> A 17. No. The Commission initiated a rulemaking procedure in November 2013 in which it will determine whether and how to formalize rules to ensure effective use of a risk-based decision-making framework for rate cases.

As demonstrated in ORA's testimony, PG&E's changing risk assessment model leads to different outcomes than PG&E would purport to have the Commission authorize with the version of their model initially provided in the rate case.[24] Liberty Consulting found:

> "risk assessments enjoying robust quantification of probabilities, consequences, and mitigation opportunities cannot happen at PG&E until 2014 at the earliest. Using such assessment to drive capital and O&M planning and budgeting will therefore not occur before that time."[25]

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[22] *See* Decision 14-12-025, pp. 29-30, and 38.

[23] Ex. PG&E-39, p. 2-7. (PG&E Rebuttal Testimony).

[24] Ex. ORA-53, pp. 3-4. (Skinner, Chapter 2, Safety and Risk Management, errata of 1/21/2015).

[25] Ex. Indicated Shippers-09, p. S-2. (Liberty Consulting Group report to SED, May 6, 2013).

The risk assessment process PG&E is utilizing is also the same process, which the Commission previously found flawed:[26]

> Mr. Bromson: And PG&E's risk assessment process for gas transportation and storage – in this proceeding, it's really part of a larger risk assessment that PG&E does for all its lines of business including gas distribution and electric generation distribution; isn't that correct?
>
> Mr. Stavropoulos: Yes, it is.

While PG&E disagrees with that assessment,[27] the risk assessment utilized in this application shows a demonstrated lack of maturity. This lack of maturity is consistent with PG&E's assertion that it "did not make any changes to its 2015 GT&S filing as a result of the 2014 GRC."[28] However, PG&E contradicted itself, stating that:

> Mr. Bromson: "'the GT&S forecast resulted from the next stage in development in implementation since PG&E's 2014 GRC application.' … Do you see that?
>
> Mr. Krannich: Yes.

PG&E's assertion the model has changed between 2013 and 2014 is consistent with ORA's own analysis that demonstrated that the 2014 risk register was substantively different than the 2013 risk register.[29] However, PG&E for purposes of the model provided to the Commission either was, or was not, the next step in its progression based on who at PG&E is providing the answer. All that parties can discern is that PG&E's model changed between 2013 and 2014. The raw scores were significantly different, the differences between scores were

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[26] 12 RT 793:7-14.

[27] 12 RT 796:27 – 797:8.

[28] Ex. ORA-61, p. A-41. (Chapter 2 Supporting Attachments).

[29] Ex. ORA-53, Table-02-2, p. 11. (Skinner, Chapter 2, Safety and Risk Management, errata of 1/21/2015).

significantly different, and the overall prioritization of the top risks were significantly different.

Table 02-2 – Comparison of Top 5 risks and scoring between 2013 and 2014 Risk Registers

2013 - Risk Register			2014 - Session D			ORA-DR-40 Q10 Atch1		
TRA3	Pre-1962 Land Movement	15.9	TRA1	External Corrosion	788	TRA1	External Corrosion	1094
TRA4	Older Seam Types	8.67	TRA3	Pre-1962 Land Movement	785	TRA3	Pre-1962 Land Movement	1092
TRA2	External Corrosion	1.21	TRA8	Internal Corrosion	583	TRA8	Internal Corrosion	810
STO16	Internal Corrosion	0.71	TRA4	Older Seam Types	581	TRA4	Older Seam Types	808
TRA7	Mechanical Damage	0.55	TRA12	Weather & Outside Forces	548	TRA12	Weather & Outside Forces	806

The change in overall prioritization calls into question PG&E's inputs. Any model requires good inputs to lead to good outputs. Without good data, the output of a model is questionable, and may lead to poor outcomes or choices. While model outputs should not be blindly adhered to, a poor model should be disregarded by decision-makers: either at a utility or those at the Commission. PG&E's risk assessment is plagued by poor data, broad scales subject to random adjustment, and scales that vary and are not defined exactly as PG&E describes them in testimony.

Data quality remains a problem for any determination of risk, as described by Mr. White:[30]

> "As has been described earlier in our testimony, the use of probabilistic models depends on the availability of data to have a credible output of those models. Because what is described, the risk assessment process that is described in 2A-11, is looking for the highest consequence type scenarios. That data largely does not exist in the industry."

Because quality data is missing, PG&E must rely on populating its risk register with subjective data provided by subject matter experts. While subject matter expertise is allowed, even accepted under current standards, it is the least exacting and accepted of the possible methods to determine risk.[31] Through its "logarithmically" based system, PG&E then introduces greater uncertainty and error into their risk register process, which then informs PG&E's

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[30] 15 RT 1318:5-16.

[31] 15 RT 1318.

program selection. Contrary to PG&E's description in testimony, the risk register is not mathematically logarithmic. As Mr. White explained during cross-examination:[32]

> Mr. Bromson: Now, I believe you testified that it's not always a perfectly mathematical log-based scale in your – in your initial range – for the ranges in your initial consequence scores; is that correct?
> Mr. White: That's correct. It's nonlinear. It approximates logarithmic.

PG&E then utilizes ranges, which is may not adhere to, or which they may then adjust from the raw value indicated by the ranges in their scale:[33]

> Mr. White: … So in that example, a 5 is [7] to 40 million and a 6 is 40 to 250 million. If it straddled that range, which one seems more appropriate? The mid point of 7 to 40 or the mid point of 40 to 250? So it's not a specific number that comes out of these scenarios that often have never occurred. And we are estimating what we think the consequences could be.

As described by PG&E's own witness, the risk register, which feeds into PG&E's decision-making processes is based on estimation, scenarios that often have never occurred, and based on data that largely does not exist. All of these items lead towards a very poor model, and is likely reflected in the drastic changes to scoring, ranking, and relative values as described in ORA's Table 02-2.

2.1.2.2.2 PG&E's Inclusion of PG&E's Business Risks and Other Non-Safety and Security Risks In its Model Is Unreasonable

Further complicating the relationship of the model's outputs to outcomes that lead to reasonable outcomes to improve safety at reasonable rates, are the weighting factors which are tilted towards reducing risk to PG&E Corporation.[34] Not ratepayers, no employees, but to PG&E as a corporation. Direct Financial Damage (30%), Reputation (5%), and Regulatory Compliance (5%) weightings mean that the 40% of the results are geared towards reducing the risk to PG&E.[35] Yes ratepayers may benefit, but that is not the focus of nearly half the weighting

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[32] 15 RT 1324:27 through 1325:5

[33] 15 RT 1328:6-14.

[34] Discussion at 15 RT 1332:25 – 1333:11.

[35] Ex. ORA-61, pp. A-15 & A-16 (PG&E Response to TURN-DR-001 Q01, Atch 02.)

of PG&E's model. The American Society for Mechanical Engineers (ASME) standards, according to Mr. White do not measure business risk.[36]

PG&E's risk assessment is even further eroded by the complete lack of a cost-benefit analysis. As simply stated during hearings:[37]

> Mr. Bromson: Did PG&E submit a cost-benefit analysis of the projects it requested to be approved in this application?
> Mr. White: Not to my knowledge.

Mr. Soto, who added some further explanation, could only conjecture that "we have the costs for the respective programs, and the benefit can be quantified through people that will receive the benefit of that risk assessment", not that PG&E had actually done so.[38]

2.1.2.3 The Commission Should Utilize the Process Adopted in D.14-12-025 For Evaluation of Risk Assessments in GRCs and Not Adopt PG&E's Risk Assessment Model In the Current GT&S

2.1.2.3.1 The D.14-12-025 Process of Review of Risk Assessment Models Is Far More Robust Than the Process In This Proceeding

The Commission in D.14-12-025 has required a far more robust process of review of utility risk assessment models than has occurred in this proceeding. Under the new procedures, there will be triennial modeling proceedings, year-ahead filings by the utilities, and annual verifications of risk mitigation and risk spending.[39] Commission staff will verify the utility reports annually. For review of the overall modeling process, the Commission may also hire expert consultants.[40]

In this proceeding, there were no formal guidelines as to how the Commission and parties should review risk assessment model. PG&E only provided their risk assessment model for review by parties not in its application itself but not until a couple of months later, upon request by parties to the proceeding, The March 5, 2012 letter directed PG&E to submit a risk

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[36] 15 RT 1340:1-6.

[37] 15 RT 1336:6-9.

[38] 15 RT 1336:20-23.

[39] D.14-12-025, OP 1, pp. 54-55.

[40] D.14-12-025, p. 28.

assessment in the 2014 GRC application and pay for outside consultants to review the risk assessments, and the consultants did not find that the risk analyses submitted by PG&E met the standard of a "risk assessment." The March 5, 2012 letter did not specifically apply to the current proceeding and PG&E did not offer to pay for outside consultants. The Commission was initially unsure in this proceeding as to how it would review PG&E's risk assessment model, and did not to hire outside consultants to review the model, with Safety and Enforcement Division itself conducting a review that was not formally submitted into evidence in this proceeding, (although PG&E and other parties filed responses to SED's comments that are on the record. The absence of any finding in this proceeding by an outside consultant or any entity reviewing PG&E's risk filing concluding that PG&E risk assessment model was methodologically sound and a reasonable method of determining which investments PG&E should undertake should prevent the Commission from approving PG&E's risk assessment model in this proceeding.

2.1.2.3.2 The E-mails in Ex. ORA-100 Casts Doubt as to the Commission's Motivations Behind the March 5, 2002 Letter Initially Requesting PG&E to Submit a Risk Assessment S

PG&E policy witness Stavropoulos testified that

> Nor would the Commission have required PG&E to perform risk assessments or brought the Safety and Enforcement Division and outside consultants into PG&E's 2014 GRC and this case to perform independent evaluations of PG&E's risk assessments if the Commission had believed that prior rate cases had adequately addressed safety.[41]

On the eve of hearings, PG&E produced approximately 65,000 e-mails, which included some improper ex parte communications between PG&E and the Commission Executive Director contemporaneous with the issuance of the March 5, 2002 letter. ORA provided some of these e-mails in Ex. ORA-100. These letters indicate that the motivations of the Executive Director, acting on behalf of the Commission, in requiring PG&E to file a risk assessment in the 2014 GRC might not have been limited strictly to concerns associated with how GRCs handle safety issues. Given that the Commission has adopted the process in D.14-12-025 to govern risk

[41] Ex. PG&E-39, p. 1-9 (Stavropoulos Rebuttal). *See generally* 12 RT 806-807.

assessment in future GRCs, and that PG&E partially derives support for its filing in this proceeding from the March 5, 2012 letter, ORA suggests the Commission would best not adopt a risk assessment model in this proceeding given potential procedural infirmities associated with that letter.

3 POTENTIAL SHAREHOLDER COST RESPONSIBILITY ISSUES

ORA recommends shareholder cost responsibilities as discussed in the sections below. For example, ORA recommends that shareholders continue to pay for 1955-1961 pressure testing and the remedial work in conducting corrosion repair.

Regarding the San Bruno fines and remedies decision, ORA understands there will be separate briefing on this issue at a later date, and so reserves its comments.

4 IMPACT OF PROPOSALS ON CUSTOMERS

PG&E's proposals would increase average residential consumer bills by approximately $5.23 a month, and small business customers by approximately $42.50 a month.[42] ORA's proposals would increase average residential consumer bills by approximately $3.38 a month, and small business customers by $27.49.[43] However, ORA notes that for residential customers in particular, the greatest bill impacts are during the winter heating seasons, and less in the warmer summer months.

5 RATEMAKING ISSUES

5.1 Amortization of Revenue Shortfall and Disallowance Due to Delayed Decision

5.2 Alternative Revenue and Ratemaking Proposals

5.3 Ratemaking Cycle

ORA continues to recommend a 3rd attrition year in the current rate GT&S cycle.[44] Given the delays in the proceeding, PG&E would be expected to file their 2018 GT&S Application no later than December 2016, or approximately within a year of the expected

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[42] *See* PG&E-2 (PG&E/Niemi), p. 17-13.

[43] *See* ORA-45 (ORA/Sabino), pp. 23-24.

[44] *See* ORA-18 (ORA/Tang), p. 43.

decision in this application. Such an early filing at this point would not allow PG&E to develop operational experience with any of the adopted recommendations from this proceeding. Adding an additional attrition year to the two attrition years that PG&E proposes would greatly benefit all parties in this proceeding, and could be accomplished easily if the Commission approves the PTY mechanism to which PG&E and ORA agreed and stipulated, by extending the mechanism by one year. Furthermore, it will allow time for better understanding of the Commission's new General Rate Case OIR process, which is expected to resume this summer.[45]

6 2011-2014 CAPITAL EXPENDITURES

7 TRANSMISSION PIPE

7.1 Overview and Summary

7.1.1 PG&E's "Programmatic" Forecasts For Its Hydrotest And Vintage Pipeline Replacement Program Are Unreasonable And Should Be Rejected

PG&E requests approximately $179 million in 2015 for Hydrotest Program expenses and $597 million for the 2015-2017 rate case period for Vintage Pipeline Replacement (VIPER) Program capital expenditures. These requests comprise the largest expense program (Hydrotest) and capital expense program (VIPER) in the entire GT&S application.[46] Notwithstanding the significant scope of these requests, PG&E's Hydrotest and VIPER forecasts do not meet the most basic test of reasonableness and therefore fail to satisfy PG&E's burden of proof in this case.

Public Utilities Code § 454 puts the burden of proof on PG&E to show that its requested rate increases are justified, not for ORA or other parties to prove that they are unreasonable. Despite this critical distinction, ORA not only demonstrates the unreasonableness of PG&E's request, but also provides reasonable forecasts for 2015 based on PG&E-generated data.

PG&E's witness sponsoring both forecasts repeatedly explained on cross examination that the key to PG&E's unit cost forecasts for both programs was that the forecasts were

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[45] *See* Decision 14-12-025, Ordering Paragraph 5. The first Safety Model Assessment Proceedings are expected by May 1, 2015.

[46] PG&E's workpapers include additional pages for work planned outside of the rate case period, or that do not directly impact PG&E's calculated costs as defined above for these two programs.

"programmatic."[47] He explained that PG&E employed a program-based methodology, instead of looking at individual cost drivers or component costs, because of the large amount of actual cost data that PG&E had from hydrotest and pipeline replacement work performed between 2011 and 2014 for PG&E's Pipeline Safety and Enhancement Plan (PSEP). He also explained how using this large amount of data would smooth out what would otherwise be highly variable unit costs if calculated on a project by project basis. He especially emphasized the "relatively large amount of data" available to PG&E to provide "a perspective on a programmatic cost level."[48]

These cross examination observations were consistent with his Rebuttal Testimony, emphasizing that "PG&E's experience over four years of conducting hydrostatic tests is that these individual test costs will smooth out at the program level, over many projects."[49]

However, in developing its "programmatic" forecasts that allegedly considered the "large amount" of "actual" cost data at PG&E's disposal, PG&E took at least three steps to ensure that its Hydrotest and VIPER Program forecasts would far exceed its reasonable actual costs during the GT&S rate case period.

First, rather than employing a truly programmatic approach that considered the "large amount" of "actual" cost data available to PG&E, PG&E cherry picked the projects it included in its forecasts. For the Hydrotest Program, PG&E developed its forecast based primarily on forecasted, rather than actual, costs, and used only one year of hydrotest work, rather than the three years of data available to it.[50] For the VIPER Program, PG&E's forecast relied on nine cherry picked projects out of 42 available PSEP projects completed in 2012 and 2013 for which

[47] Mr. Barnes testified as follows: 17 RT 1721:24 – 1722:14: (Regarding both the Hydrotest and VIPER Program forecasts: "And very simply put, the costs that we came up with are much more in a programmatic level. And we are not looking -- because these are such large programs, we are not looking to put forth a proposal in this rate case that's based on individual cost element breakdowns down to the minutia because what we found is that <u>from a programmatic perspective</u>, that's really not a necessity in order get the high level understanding of what the costs should be. <u>We've had four years of experience with hydrostatic testing, four years of experience with pipe replacement</u> at a very large programmatic perspective and have a pretty good understanding of what financial costs per mile are associated with those programs.")

[48] 18 RT 1920:2-6 (Barnes/PG&E) (emphases added).

[49] Ex. PG&E-39, (Rebuttal Testimony), p. 4A-42:9-11 and 5-13 generally.

[50] See the discussion at Section 7.4.2 below.

actual cost information was available.[51] For both program forecasts, PG&E offered no explanation for why or how the data it used was representative of the work it proposed to perform in GT&S, and all the evidence suggests that, in fact, it is not representative and overstates the costs PG&E will incurring during the rate case period.

Second, for both its Hydrotest and VIPER Program forecasts, PG&E assiduously (to the point of intentional ignorance) refused to consider evidence that its costs could, and would likely, go down significantly during the rate case years between 2015 and 2017.[52] Instead, PG&E asserts it will experience rising cost pressures, but fails to provide any evidence of these pressures.

Third, for the Hydrotest Program, PG&E padded its costs with additional costs it claims were associated with the Pipeline Safety and Enhancement Plan (PSEP) hydrotest program, costs which PG&E could and should have included in its PSEP Quarterly Reports pursuant to Commission decision, but did not.[53]

In contrast, ORA's Hydrotest and VIPER program forecasts present true "programmatic" forecasts. Like the programmatic forecasts described by PG&E's witness – but not implemented by PG&E – ORA's forecasts rely upon the "rich data set of costing"[54] provided by PG&E in its PSEP Quarterly Compliance Reports filed with the Commission. ORA relies only upon actual costs reported costs and uses *all* PSEP projects completed between 2011 and 2013. Where data is excluded, clearly articulated reasons are provided.[55] For these reasons, ORA's forecasts should be adopted in lieu of PG&E's inflated and unreasonable forecasts for both its Hydrotest and VIPER programs. Each of these issues is discussed in detail in Sections 7.4 (Hydrostatic Testing) and 7.6 (Vintage Pipeline Replacement Program) below.

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[51] See the discussion at Section 7.6.3 below.

[52] See the discussions at Sections 7.4.3 and 7.6.9 below.

[53] See the discussion at Section 7.4.4.1 below.

[54] 19 RT 2122:21 (Barnes/PG&E).

[55] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 23, note 64.

7.1.2 The Commission Should Clearly Define Work Priorities For Hydrotesting And Replacement Of Pipelines, Should Disallow Certain PSEP-Related Costs, Should Audit PG&E PSEP Accounting, And Should Order Cost Reporting By PG&E

ORA makes the following general recommendations applicable to both the Hydrotest and VIPER Programs: (1) to ensure that work in these programs is properly prioritized and takes into account work prioritized for completion pursuant to earlier Commission orders, and (2) to require PG&E to revise its accounting practices and provide cost reports that will facilitate implementation of cost saving programs and the accuracy of future forecasts:[56]

1. **Prioritization:** The scope of all work performed in 2015-2017 needs to be clearly defined for prioritization.[57] To this end, the Commission should expressly identify deferred PSEP work[58] and the GT&S decision trees associated with both programs – which establish the work priorities for those programs - should be updated to include deferred PSEP pipe segments;

2. **Deferred PSEP Work:** As discussed in ORA's Testimony, the hydrotest and replacement costs for deferred PSEP work should be subject to the cost limitations established in D.12-12-030 and the Commission should confirm that PG&E has correctly applied the cost provisions of that decision.[59] PG&E should not be allowed to bypass the PSEP cost caps by deferring work to this case;

3. **Hydrotests For 1955-61 Pipes:** The cost limitations for pipe segments installed post-1955 adopted by D.12-12-030 should be applied for all PG&E hydrotest work, and for all pipe segment replacements initiated by a lack of records, as discussed in Section 7.4.5 below;[60]

4. **Commission Oversight:** If the Commission grants PG&E the flexibility it has requested to modify the scope of either program, the Commission must provide adequate oversight through structural safeguards to ensure that the highest priority work is performed in an appropriate time frame, regardless of the cost consequences to PG&E;[61] and

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[56] See generally Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 5-8.

[57] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 11-14 and 57-64.

[58] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 11-14 and 57-64

[59] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 11-13 and 57-64.

[60] See also Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 28-29,

[61] Because PG&E may have to test or replace lines subject to cost disallowances, PG&E has the incentive to avoid performing this work in favor of work which is subject to full cost recovery. The Commission

5. **Quarterly Cost Reports:** Similar to what was done in D.12-12-030 regarding the PSEP Quarterly Compliance Reports, with modifications to ensure collection of specific types of information, the Commission should order PG&E to collect and report on cost data for both the Hydrotest and VIPER Programs to facilitate more accurate forecasts in the next rate case.[62] The evidence of PG&E's accounting practices discussed in Sections 7.4 and 7.6 herein, and its inability to produce basic cost information to identify cost-saving opportunities, demonstrate the need for such reports, and for the audit requested below.

6. **Commission Audit:** As discussed briefly in Section 7.4.4.5, and for reasons revealed throughout the arguments in Sections 7.4 and 7.6 herein, the CPUC should perform an audit of the PSEP program once that program is completed to ensure that accurate data is available as a baseline against which to evaluate future GT&S cost performance, and to use in forecasting costs in subsequent cases. This audit would not result in changes to in the costs approved in this case or those approved in PSEP, but instead would provide an accurate baseline for hydrotest, pipe replacement, and other costs in future proceedings, and would order revisions to PG&E's reporting obligations to the extent appropriate to facilitate understanding of PG&E's costs to encourage efficiencies and/or forecasting in other proceedings.[63]

7.2 In-Line Inspections

7.3 Direct Assessment

7.3.1 External Corrosion Direct Assessment

ORA recommends a 2015 forecast of $22.976 million for Direct Assessment as compared to PG&E's forecast of $46.521 million.[64] ORA does not oppose PG&E's request for $2.857 million for Stress Corrosion Cracking DirectAssessment. Part of ORA's recommendations for

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will need to establish structural safeguards, including monitoring functions, to ensure work subject to disallowances is performed in a timely and appropriate manner no different than work subject to full cost recovery. See, e.g, Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 67.

[62] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), 68. See also Section 7.4.4.1 (describing what D.12-12-030 ordered).

[63] Ex. ORA-47 (Supplemental Testimony), p.3.

[64] Ex. PG&E-01 (Barnes/PG&E), pp. 4A-27-28.

these lower forecasts is discussed in Section 7.3.3 as part of the reclassification of pipes from distribution to transmission.

7.3.2 Internal Corrosion Direct Assessment

PG&E requests $28.8336 million for External Corrosion Direct Assessment (ECDA), as compared to ORA's forecast of $12.849 million.[65] In order to derive this forecast, ORA used the recorded number of 2013 ECDA digs/project ratio of PG&E.[66] PG&E conducts multiple upward roundings throughout its analysis of digs/projects, over a period of ten years including outlier years in 2004-2005 with much higher digs/project ratio in order to inflate its request.[67] PG&E tries to justify its double rounding by explaining that a partial dig cannot be done. ORA disagrees that because on a specific project there can be only a whole number of digs when calculating an average of digs/projects for multiple projects a non-whole number can certainly occur even if each project has a whole number of digs. Even if that rounding up was reasonable, rounding up twice is not, as across a multi-year program there certainly can be partial digs, and certainly there can be fractions of digs for ratemaking purposes.

7.3.3 Reclassification of Pipelines from Distribution to Transmission

ORA's recommendation that the shift of 920 miles from being defined as distribution to transmission be delayed until 2017 is reasonable.[68] PG&E's position on whether or not they received funding through the 2014 GRC has shifted throughout this proceeding. On September 23, 2014 PG&E provided a data response that indicated they could not track the funding for the ongoing maintenance of these pipes.[69] This answer remained the same in the updated response provided on November 17, 2014.[70] PG&E's answer began to change in a data response provided October 9, 2014, PG&E stated: "PG&E cannot extract the costs from the GRC for DIMP related

[65] Ex. ORA-07 (Phan/ORA), p. 11.

[66] Ex. ORA-07 (Phan/ORA), p. 12.

[67] Ex. ORA-106 (ORA DR-131 Q3).

[68] Ex. ORA-07 (Phan/ORA), pp. 16-19.

[69] Ex. ORA-105 (Data Requests related to the transfer of 920 miles of pipeline from distribution to transmission), ORA DR-119 Q1, p. 6; and ORA DR-121 Q1, p. 16.

[70] Ex. ORA-105 (Data Requests related to the transfer of 920 miles of pipeline from distribution to transmission), ORA DR-119 Q1, Rev1, p. 12.

costs associated with the risk analysis of these 920 miles, because we do not account for these risk analysis costs at a pipeline segment level."[71] In response to a different question, PG&E on the same day replied, again, that costs were part of the GT&S rate case and were not covered under DIMP.[72]

During cross-examination, PG&E's witness clearly stated:[73]

> Mr. Bromson Q: So did you receive DIMP funds in the 2014 GRC to cover the miles before they were reclassified as transmission?
> Mr. Barnes A: Yes. And if I may further explain, the – under the DIMP program, that program is really geared towards a distribution integrity management support of Subpart P.

Clearly, these 920 miles have been, and currently are still being paid for by ratepayers in the 2014 distribution GRC. PG&E was aware of the rulings leading it to change this classification early in the 2014 GRC proceeding but kept those miles in the GRC. Allowing PG&E to move forward, given their complete lack of cost accounting, would allow PG&E to double-dip and collect funds twice from ratepayers to ensure integrity management of the same pipes. Since PG&E cannot ascertain how much money they have spent, or will spend, from the GRC, their proposal to collect further funds from ratepayers in 2015 and 2016 is without merit and should be rejected.

7.4 Hydrostatic Testing

7.4.1 Overview – PG&E Hydrotest Program Forecast Is Unreasonable; ORA's Forecast Is More Likely To Accurately Forecast PG&E's Actual Program Costs

Recognizing the significant deficiencies in PG&E's pipeline records, and consistent with a recommendation from the National Transportation and Safety Board (NTSB), in Decision 11-06-017 the Commission ordered all California natural gas transmission pipeline operators, including PG&E, to prepare plans to either pressure test or replace all pipes which were not

[71] Ex. ORA-105 (Data Requests related to the transfer of 920 miles of pipeline from distribution to transmission), ORA DR-136 Q1, p. 22.

[72] Ex. ORA-105 (Data Requests related to the transfer of 920 miles of pipeline from distribution to transmission), ORA DR-136 Q2, p. 27.

[73] 17 RT 1671:15-21.

pressure tested or lack sufficient records to document a test was performed.[74] PG&E has stated that following completion in 2014 of its PSEP work authorized in D.12-12-030 (the PSEP Decision), it will still have 1,500 miles of pipe operating over 20% SYMS without traceable, verifiable, and complete records of a modern pressure test.[75]

To comply with the Commission's test or replace order, PG&E proposes a testing target of 170 miles a year during the rate case period, for a total of approximately 510 miles tested between 2015 and 2017.[76] Based on a combination of actual and forecasted costs experienced in 2013, PG&E forecasts a unit cost of $0.97 million per mile for 2013 projects, which PG&E escalates to obtain a 2015 unit cost forecast of $1.02 million per mile.[77,78] If PG&E's 2015 Test Year forecast of $179.2 million for the Hydrotest Program is adopted, PG&E will collect approximately $538 million over the rate case period, plus escalation through the attrition mechanism. However, the record clearly demonstrates that PG&E's costs will decline over 2016 and 2017, therefore ORA recommends a lower 2015 Test Year forecast to account for the attrition mechanism.

PG&E's 2013 unit cost forecast of $0.97 million per mile is only one of four 2013 unit costs proposed for developing the 2015 unit cost forecast for the Hydrotest Program. In contrast to PG&E's proposal based on a *mix* of actual and forecasted costs, the others include calculations based on *actual costs* as follows:

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[74] D.11-06-017, p. 19.

[75] Ex. PG&E-1 (Direct Testimony), p. 4A-33.

[76] See Ex. PG&E-1 (Direct Testimony, Chap. 4A, Barnes), p. 4A-32 for the annual target. 2015-2017 proposed projects, listed in workpaper pages WP 4A-52 to WP 4A-53, have annual mileages of 171.0, 168.4, and 172.0 miles respectively.

[77] Ex. PG&E-4 (Workpapers, Chap. 4A, Barnes), p. WP 4A-51. PG&E's tables in this workpaper incorrectly shown a strength test unit cost and 2015 forecast before escalation. The true 2015 unit costs is $173.970 million from Table 4 divided by 170 miles from Table 3, which yields $1.02 million per mile. PG&E also requests capital expenditures for this program which are not addressed here. This includes 2015 forecasted capital expenditures of $21.4 million to modify pipelines prior to hydrotesting and $2.92 million for LNG/CNG equipment to supply customers during hydrotests. See Ex. PG&E-1 (Direct Testimony, Chap. 4A, Barnes), Table 4A-9, page 4A-32.

[78] PG&E's 2015 expense request for Hydrotest consists of $174.0 to perform strength tests, and $5.3 million for "uprates." See Ex. PG&E-4 (Workpapers, Chap. 4A, Barnes), p. WP 4A-51. ORA did not challenge PG&E's request regarding uprates.

1. ORA's calculation of $0.72 million per mile based on 2013 costs reported in the PSEP Quarterly Compliance Reports
2. ORA's alternative calculation of $0.63 million per mile based on other actual cost data provided by PG&E[79]; and
3. TURN's forecast of $0.84 based on PG&E-reported actual 2013 PSEP costs.[80]

This brief focuses on the differences between PG&E's 2013 forecast of $0.97 million per mile and ORA's calculation of a 2013 unit cost of $0.72 million per mile based upon the 2013 PSEP costs PG&E reported in its PSEP Quarterly Compliance Reports.

PG&E claims to have developed its unit cost forecast for the Hydrotest Program using a "programmatic" approach that takes advantage of the "large amount" of actual cost data that PG&E's has collected through its PSEP work.[81] PG&E's witness explained:

> We've had four years of experience with hydrostatic testing, four years of experience with pipe replacement at a very large programmatic perspective and have a pretty good understanding of what financial costs per mile are associated with those programs.[82]

[79] Ex. ORA-34, p.24 and Ex. ORA-79, Narrative Description of Workpapers, pp. 9-14.

[80] Ex. TURN-4, p. 27. PG&E rebuttal testimony states that the more current data results in a unit cost of $.85 million per mile. See Ex. PG&E-39, p. 4A-53. PG&E acknowledges that TURN's recommendation is based on actual recorded costs for 2013 per PG&E's accounting reports. See Ex. PG&E-39, p. 4A-53 and p. 4A-49, Table 4A-10. ORA testimony supports the use of recorded costs as preferable to forecasted costs in forecasting hydrotest costs for GT&S. See Ex. ORA-34, p. 26.

[81] See Note 47, above. See also 17 RT 1792:7-15 (Regarding the Hydrotest forecast: "…[W]e've gotten to the point where we're now at least in the '90s where we have the ability to sort of look at what we have. And we know what we have. And so generating a program level, detailed cost at the level of what we were doing at that time doesn't make as much sense as putting a program forecast together *based on where we've been historically*. And so that's kind of what we've done.") and 17 RT 1770:11-21 (Explaining why PG&E didn't consider cost drivers such as mercury cleaning and water management when it prepared its Hydrotest Program forecast: "We used the information that was related to the fact that we have an appropriate assessment that's pretty common when you have *large quantities of work to spread the unit costs across the program* to come up with a *programmatic approach and programmatic value* that seems to work. I've done it. I represented to you earlier how an ILI program at El Paso I did the same thing [see 17 RT 1727-1728] and it worked great.") (emphases added).

[82] 17 RT 1722:8-14 (Barnes/PG&E).

PG&E's witness confirmed that this programmatic perspective was based on a review of 2013 costs – some actual and some forecasted – and divided by the corresponding number of miles forecasted to arrive at its forecasted unit cost.[83]

PG&E argues that such a simplistic, programmatic approach is appropriate because, among other things, it takes advantage of the "large amount" of actual cost data available to PG&E and it spreads out the "variability" of individual project costs to arrive at a reasonable unit cost.[84]

While a programmatic methodology may be appropriate here, the record demonstrates that PG&E's application of that methodology is unreasonable because:

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[83] 18 RT 1859:2 – 1860:17 (Barnes/PG&E):

Q … [T]o be clear, for the hydrotest forecast, PG&E simply took all the PSEP actual costs and some forecasts, as we discussed yesterday, for 2013 and based that forecast on some sort of average of all of the projects. Is that a fair, high-level explanation of what PG&E did?

A It's close. So the clarification I'll put on that is that we looked at the forecast. So we certainly had actuals in 2013 and we had end-of-the-year forecasts for 2013 which were moving toward $970,000 a mile. And so that's the clarification that I would put on that, is that we identified that as a reasonable expectation going forward with some escalation.

Q Okay. And your forecast doesn't specifically consider individual cost drivers like pipe cleaning to see if those costs are going to go up and down -- up or down over the GT&S period; is that correct?

A No. At this point in time what we are doing is we are looking at the actual costs over a period of time and looking at the lowest expected actual costs over the period of time and using that to predict what we think we can do over the longer period of time of the GT&S rate case. So –

Q …. When you say actual costs, you mean total actual costs?

A Yes.

Q For 2013?

A I may have mischaracterized it. So for 2013, I'm still talking about the forecast itself contains actuals combined with forecasts for 2013 that yielded $970,000 a mile. So, yes. Thanks for the correction.

See also 19 RT 2084-2084 (Barnes/PG&E) (Explaining how the Hydrotest Program forecast was calculated and confirming that it is indifferent to diameter and other variables); and Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 22.

[84] 17 RT 1727:26 -1728:8 (Barnes/PG&E).

1. It starts with a forecast of costs, rather than relying upon the "large amount" of actual cost data available to it.[85]

2. PG&E refused to look at the actual cost trends in its data between 2011 and 2013, and also refused to consider evidence that its costs could, and likely would, go down meaningfully between 2015 and 2017 based on efficiency gains and the fact that the work performed in 2013 is not similar to the work proposed to be done during the rate case period; and

3. PG&E padded its 2013 hydrotest forecast with additional costs it claims were associated with PSEP, costs which PG&E should have included in its PSEP Quarterly Compliance Reports, but did not.

Given the "rich data set of costing"[86] and other information available to PG&E, it is clear that PG&E made conscious choices to develop an unreasonably high forecast based on only a partial year of actual cost data, thereby shifting the burden to other parties to show the unreasonableness of its proposal. Employing PG&E's "programmatic" approach – but using PSEP Quarterly Compliance Report data for all hydrotest projects completed in 2013 – ORA calculates that PG&E's 2013 unit costs were \$0.72 million per mile, not the \$0.97 million per mile forecasted by PG&E.[87] ORA further concludes that the trend of falling hydrotest costs reflected in PG&E's 2011 through 2013 actual costs will continue into 2015 for a number of reasons discussed below. ORA's regression analysis based on that data results in a 2015 forecast of \$0.56 million per mile,[88] nearly half that of PG&E's \$1.02 million per mile GT&S forecast,[89] but similar to PG&E's original PSEP forecast of \$0.502 million per mile for hydrotesting.[90] As discussed in Section 7.6.7 below, PG&E's PSEP forecast was prepared by an expert witness, defended by PG&E executives, subjected to extensive discovery and hearing, and adopted essentially as proposed in D.11-12-030.[91] It is therefore an appropriate benchmark for the

[85] 18 RT 1920:2-6 (Barnes/PG&E).

[86] 19 RT 2122:21 (Barnes/PG&E).

[87] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 20, Table 4C-4.

[88] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 23.

[89] PG&E's 2015 forecast is \$1.02 million per mile when its proposed escalation rate of 5.5% is included.

[90] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 15.

[91] Also see Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 15-16.

reasonableness of ORA's 2015 forecast, and for the unreasonableness of PG&E's proposals in this case.

Quantitatively, the difference between ORA's 2015 unit cost forecast of $0.56 million per mile and PG&E's forecast of $1.02 million per mile is based on three components:

1. PG&E's forecast is based on forecasted 2013 costs rather than actual PSEP costs;
2. ORA's forecast is based on actual PSEP costs publicly reported by PG&E in its PSEP Quarterly Compliance Reports; and
3. ORA's forecast is based on a regression analysis of 2011-2013 actual costs, while PG&E uses a single data point for 2013 derived from forecasted costs, and a generic escalation rate to arrive at its 2015 forecast.

Given that ORA's 2015 unit cost forecast of $0.56 million per mile is the only truly programmatic forecast which considers all of the relevant actual cost data, and takes falling hydrotest costs into account, ORA proposes its forecast be used as the basis for the Test Year forecast in lieu of PG&E's.

7.4.2 PG&E's Hydrotest Program Forecast Is a Mix of Actual and Forecast Costs Associated With a Subset Of The Relevant Data And Therefore Does Not Present A Reasonable Picture of What PG&E's Hydrotest Program Costs Will Be

PG&E's 2015 Hydrotest Program forecast is $179.245 million, which includes $173.970 million for strength tests and $5.275 million for "uprates."[92] The $173.970 million forecast for strength tests in 2015 is based on a 2013 forecasted average unit cost of $.97 million per mile, escalated to $1.02 million per mile and then multiplied by the 170 recoverable miles that PG&E represents it will hydrotest in 2015.

In contrast, ORA's 2013 unit cost calculation of $0.72 million per mile is adjusted downward to $0.56 million per mile to reflect PG&E's falling hydrotest costs during the rate case period, and adjusted to remove testing costs associated with pipe installed after 1955, resulting in a Test Year program forecast of $91.72 million, $87.5 million less than PG&E's request.

PG&E justifies its 2015 $1.02 million per mile forecast by claiming that it is based on "historical costs" and that it is similar to its forecasted 2013 costs:

[92] Ex. PG&E-4 (Workpapers), p. WP 4A-51. ORA did not challenge PG&E's request regarding uprates.

> PG&E proposes a unit cost of $0.97 million per mile for 2015 for the expense portion of the testing. This unit cost is similar to the *forecasted* 2013 cost per mile. PG&E believes that this cost per mile and resulting program expense cost is reasonable because it is based on *historical costs*.[93]

On cross examination, PG&E's witness repeatedly emphasized the "programmatic" methodology used by PG&E to develop its 2015 Hydrotest and VIPER unit cost forecasts.[94] His point was that a programmatic forecast can take a large amount of highly variable actual project cost data and by averaging it out, will arrive at a fairly accurate unit cost for a program. He emphasized these points repeatedly, explaining the value of putting "a program forecast together based on where we've been historically,"[95] relying upon "historicals,"[96] a "rich data set of costing,"[97] "actual costs,"[98] "look[ing] at those actuals,"[99] and reviewing a "relatively large amount of data"[100] in order to "spread all those -- all that variability over the program"[101] so that "you wind up with a program that -- that has a rational level of funding associated with it."[102] By example, he explained that he used two years worth of data "to really understand what actual costs were doing" when he employed the same forecasting methodology for the In-Line-Inspection program he managed for El Paso Natural Gas Company.[103] He also repeatedly

93 Ex. PG&E-1 (Direct Testimony), p. 4A-41 (emphases added). PG&E's workpaper supporting this testimony, Ex. PG&E-4, p. WP 4A-51, incorrectly show a strength test unit cost and 2015 forecast before escalation. The true 2015 unit costs is $173.970 million from Table 4 divided by 170 miles from Table 3, which yields $1.02 million per mile.

94 See Notes 47 and 81 above.

95 17 RT 1792:7-15 (Barnes/PG&E).

96 19 RT 2122:21 (Barnes/PG&E).

97 19 RT 2122:21 (Barnes/PG&E).

98 21 RT 2344:8-15 (Barnes/PG&E) (Explaining to the ALJ his experience with ILI forecasting for El Paso).

99 19 RT 2121:24 – 2122:26 (Barnes/PG&E) (Responding to a question about the VIPER forecast, but explaining programmatic costs and his LI work at El Paso generally).

100 18 RT 1920:2-6 (Barnes/PG&E) (Regarding the VIPER forecast).

101 17 RT 1727:9 – 1728:8 (Barnes/PG&E) (Regarding programmatic forecasts generally and his ILI experience at El Paso).

102 17 RT 1727:9 – 1728:8 (Barnes/PG&E) (Regarding programmatic forecasts generally and his ILI experience at El Paso).

103 21 RT 2344:8-13 (Barnes/PG&E) (Explaining to the ALJ his experience with ILI forecasting for El

referred to the four years of data available to PG&E, as if to imply that all of that data was used in PG&E's forecast.[104]

ORA agrees with Mr. Barnes' explanation of how a programmatic forecast should be developed and the potential value of such a methodology in "smoothing" out cost differences among projects. However, PG&E's rhetoric does not match its methodology. PG&E repeatedly emphasized the use of actual or historical costs, but primarily used vague and ill-defined forecasted costs to arrive at its 2013 PSEP forecast of $0.97 million per mile.[105] Thus, while PG&E repeatedly emphasized the need to consider a "large amount" of actual cost data, it did not follow its own advice.

Further, PG&E's GT&S Application was misleading regarding its reliance on forecasted costs for its Test Year Hydrotest Program forecast of $1.02 million per mile. In written testimony PG&E explained: "PG&E believes that this cost per mile and resulting program expense cost is reasonable because it is based on *historical costs*."[106] As described above, PG&E's forecast is based on a forecast; "historical costs" are not forecasts, although they ideally are used to inform a forecast.

More troubling than its misrepresentation, PG&E's witness sponsoring the forecast was unforthcoming regarding how much of PG&E's 2013 unit cost forecast was based on forecasted as opposed to actual costs. Although PG&E's witness affirmed that he was comfortable testifying regarding the specifics of how the forecast was developed,[107] he could not identify the

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Paso: "…[B]eginning in about 2005 and then sort of honing it a little bit through 2007, we began to take just about a two-year look back really to understand what actual costs were doing to feed into our future forecasting.").

104 See Note 47 above.

105 Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 22. ORA estimates that 75% of PG&E's Hydrotest Program forecast is based on estimates, rather than actual costs based on two examples from PG&E workpapers, Ex. PG&E-4, p. WP 4A-4, lines 159 and 160. Lines 161 on the same page and line 323 on page WP 4A-7 are additional example. These four line item forecasts sum to $180.9 million, which is 77.0% of PG&E's total hydrotest expense of $235.1 million, and 95.2% of PG&E's $190 million strength test forecast. See PG&E-4, p. WP 4A-50, Table 1.

106 Ex. PG&E-1 (Direct Testimony, Chap. 4A, Barnes), p. 4A-41, emphasis added.

107 17 RT 1729:2-10 (Barnes/PG&E).

cut off date for using actual as opposed to forecasted costs in the forecast,[108] nor could he even estimate how much of the forecast was comprised of actual as opposed to forecasted costs.[109] Nor was this information clearly provided in PG&E's workpapers related to the forecast.

ORA calculates that over 92% of PG&E's costs included in its $190 million forecast for 2013 "strength test" were based on vague forecasts.[110] While PG&E had to use some level of forecasting of 2013 costs to prepare its Application, relying on 92% forecasted costs, and then being unforthcoming about this fact represents a strategic choice by PG&E.[111] The impact of of this choice is revealed by TURN's determination that using PG&E-provided recorded PSEP costs for 2013 results a unit cost of $0.84 million per mile, a more than 15% difference.[112] PG&E had the opportunity to correct its forecast based on this updated information, but instead chose to argue that its forecast of 2013 PSEP costs was superior to the use of 2013 actual costs, with no factual support for this assertion.[113]

7.4.3 PG&E's Refusal To Consider Likely Cost Reductions During the Rate Case Period Demonstrates That Its Forecast Is Unreasonable

When asked whether PG&E anticipated any falling costs in its program – as a result of efficiency gains or other factors – PG&E's witness repeatedly emphasized that PG&E would be "trying to achieve a $970,000-a-mile forecast" and working hard to keep hydrotest costs down to that level.[114] He claimed "[t]here continue to be upward cost pressures" but pointed only to

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[108] 17 RT 1731:22 – 1732:16 (Barnes/PG&E).

[109] 17 RT 1733:24 – 1734:2 (Barnes/PG&E). See also generally 17 RT 1729-1734 (Barnes/PG&E).

[110] See Note 105 above.

[111] See Note 105 above.

[112] Ex. TURN-4, p. 27. PG&E rebuttal testimony states that the more current data results in a unit cost of $.85 million per mile. See Ex. PG&E-39 (Rebuttal Testimony), p. 4A-53. $.97/$.84 = 1.154 or a 15.4% increase.

[113] Ex. PG&E-39 (Rebuttal Testimony), p. 4A-53.

[114] 17 RT 1738:4-8 (Barnes/PG&E). See also 17 RT 1740:1-19 (Barnes/PG&E) ("[Q A]re we now seeing a flat line so PG&E has not built into this forecast any possibility for efficiencies and more cost savings? A Well, so the only thing that we built into this -- we're still looking at $970,000 a mile unit costs for 170 miles proximately a year for 2015, '16, and '17. We're using that as the cost basis for the request, and -- and we believe that our continuous drive to gain those efficiencies can help us stay closer to flat line. Now, can I assure you we're not going to creep up due to some unforeseen circumstances? I did not assert to that now. But I can certainly tell you that we're putting our best foot forward with this and making sure

"shorts we have in the early part of this program" as an example of those upward cost pressures.[115]

PG&E's witness suggested that any efficiency gains would only serve to "help us stay closer to flat line" and explained that PG&E would "do everything in our power to maintain that flat line state" as if this would be a significant challenge.[116] When asked what types of efficiencies PG&E was pursuing to stabilize costs against rising cost pressures, PG&E's witness professed ignorance, stating: "So I cannot speak to those very specific implementation details."[117]

Once again, PG&E's rhetoric does not match reality. If PG&E was truly concerned that its forecast could result in undercollection of expenses, it would have performed more analysis to more accurately determine what its costs were going to be, and ultimately adjusted its forecast upward if that analysis showed it was anywhere near "that flat line state" that might result in undercollection of its actual costs. Among other things, PG&E would have studied hydrotest cost drivers, including pipe cleaning and water management costs, and looked for ways to bring those costs down to prevent against undercollection. PG&E would also have looked harder at the types of projects that were performed between 2011 and 2013 to understand whether those projects were substantially similar to, or different from the projects proposed for the rate case years.

However, the record shows that PG&E did *none* of that analysis to ensure that its forecast would not result in undercollection of its actual costs. In fact, PG&E's witness claimed such inquiries were "irrelevant."[118] However, they were only "irrelevant" because PG&E knows that

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that -- that we do everything in our power to maintain that flat line state."). See also 17 RT 1776:14-22 (Barnes/PG&E).

[115] 17 RT 1776:14-22 (Barnes/PG&E).

[116] 17 RT 1740:5-19 (Barnes/PG&E). See also 17 RT 1776:16-22 (Barnes/PG&E).

[117] 17 RT 1776:23-28 (Barnes/PG&E).

[118] See, e.g., 17 RT 1771 - 1774 (Barnes/PG&E). Mr. Barnes admits PG&E cannot quantify any specific cost drivers for the PSEP program, such as water management, pipe cleaning costs, and excavation of taps – all costs that PG&E claimed were higher than expected in PSEP and therefore had an impact on the actual cost data. Ultimately he sums up:

> I appreciate your need to … have an answer to that question. I don't have that answer. The reason I don't have that answer is *because it seems irrelevant* in relationship to what is necessary after

its forecast is more than ample to cover its costs during the rate case period. For example, the record shows that while PG&E identified work that it claims significantly drove up hydrotest costs during PSEP – including mercury cleaning and waste water management[119] – PG&E took no steps to better understand those costs to ensure that they would not lead to costs in excess of its forecast.[120]

As discussed in the following sections, the record shows that there are many factors PG&E refused to consider that will likely lead to significantly *reduced* hydrotest costs over the rate case period. In sum, PG&E data and other evidence shows that PG&E experienced significant falling hydrotest costs between 2011 and 2013, and that this trend of falling costs should continue into and during the rate case period due to continuing efficiency gains and changes in the nature of the hydrotest program, including significantly longer project lengths.

PG&E did not consider any of these factors in its forecast because it was not in its interest to do so; any evidence of falling costs would have required PG&E to reduce its forecast, or explain why a lower forecast was not justified. By strategically ignoring factors likely to lead to falling costs, PG&E attempts to shift the burden to other parties to show these falling costs exist and require a downward adjustment to PG&E's forecast.

7.4.3.1 PSEP Data Indicates That PG&E Will Experience Falling Hydrotest Costs Through 2015 As A Result Of Efficiency Gains

ORA's Direct Testimony explains how an analysis of actual PSEP project costs from PG&E's PSEP Quarterly Compliance Report data not only supports significantly lower unit costs than PG&E forecasted for its Hydrotest Program, but also shows a clear downward trend in hydrotest costs between 2011 and 2013.[121] ORA's witness explained that such a trend is to be

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> having four years of -- of individual line item experience to be able to produce a high cost forecast for a program. 17 RT 1773:21-28 (Barnes/PG&E) (emphases added).

See also 19 RT 2082-2084 (Barnes/PG&E) (discussing more details regarding the Hydrotest Program forecast, including how the programmatic approach makes variation among pipe diameters irrelevant, even though smaller pipe diameters cost less to hydrotest).

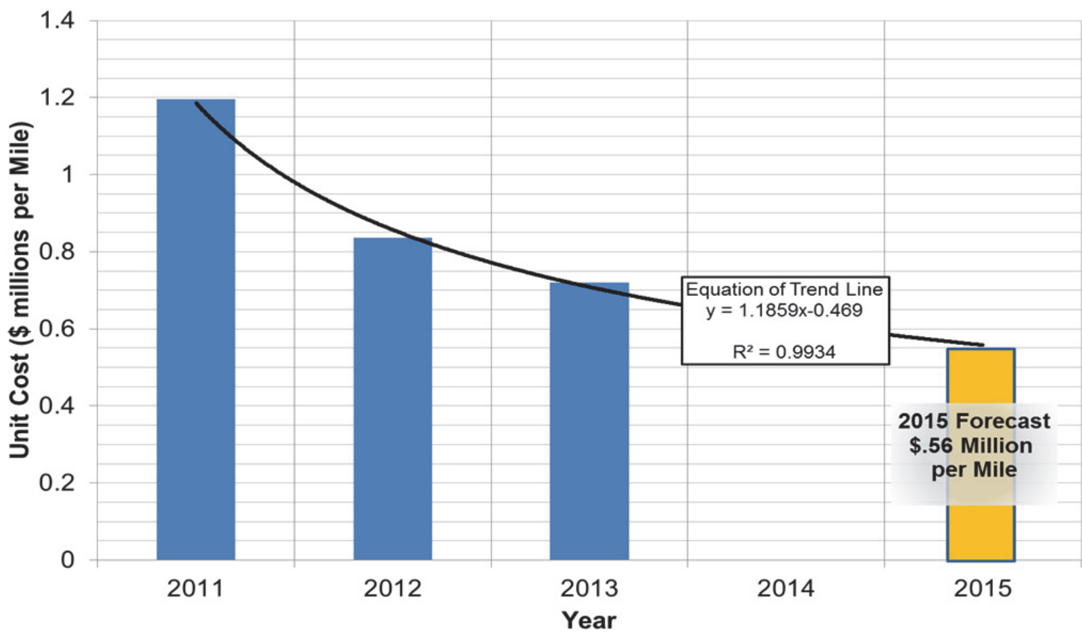
[119] Ex. PG&E-39 (Rebuttal Testimony), p. 4A-44.

[120] See Note 118 above.

[121] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts) pp. 22-26.

expected when a new program is started, as the company experiences a learning curve. ORA's witness provided the following figure illustrating this trend, and extrapolating costs out two years to provide forecast costs for 2015 that take into account the likely continuation of the declining hydrotest cost trend:

Figure 4C-1 from Ex. ORA-39, p. 23
Declining Hydrotest Unit Costs Based on PSEP Reported Costs



ORA's witness explained that this figure, using recorded 2011, 2012, and 2013 costs from PG&E discovery responses, extrapolates a 2015 cost of approximately $0.56 million per mile using a trend line based on a power equation.[122] The power equation is a form of "experience curve" which describes how costs decline as experience increases. Exhibit ORA-79, the narrative description of ORA's Exhibit 4C Workpapers, shows that this equation provides the best match to PG&E's reported cost data.[123]

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[122] The equation of the trend line is 1.11859X^-0.469 where x is equal to 1 for 2011. Using x=5 for 2017 yields $0.557 million per mile. The R^2 (R squared) value of 0.9934 indicates an excellent fit to the data. See Ex. ORA-79 (Narrative of Workpapers), pp 5-9. As explained in Note 64 of ORA-34, 2014 data was not used for a number of reasons, including the fact that it was based on crude and opaque cost estimates at the time this figure was produced and PG&E's representations regarding the "shorts" required in 2014, rending it an anomalous year for hydrotest purposes.

[123] See http://en.wikipedia.org/wiki/Experience_curve_effects Information regarding additional analyses run by ORA is provided in Ex. ORA-34, pp. 23-24, Notes 67 and 68 and in the Ex. ORA-79, Narrative of

PG&E's witness challenged ORA's regression analysis by adding a *forecast* of 2014 unit costs to its recorded costs for 2011-2013 to demonstrate that PG&E's actual costs were forecasted to go up in 2014, contrary to ORA's analysis.[124] However, PG&E's inclusion of 2014 in such an analysis is inappropriate for at least two reasons.

First, PG&E admitted that that 2014 contained "shorts" resulting in "upward cost pressures" for that year,[125] thus suggesting that 2014 was an anomalous hydrotesting year.

Second, PG&E's witness claimed that these "upward cost pressures" would continue into the Hydrotest Program because there are "many shorts …in the early part of this [hydrotest] program."[126] However, this assertion is contradicted by PG&E's own evidence regarding the projected lengths for the GT&S Hydrotest Program. While PG&E failed to identify the criteria for classifying a project as a "short" in this proceeding,[127] it established a minimum length in PSEP of 600 feet, below which PG&E proposed replacement in lieu of hydrotesting as a more cost effective mitigation.[128] ORA review shows that only four of the 153 GT&S hydrotest projects are shorter than 600 feet, and only seven are less than 1,000 feet.[129] Further, as discussed in Section 7.4.3.3 below, the average length of projects for the rate case years will far exceed the average length experienced in 2013. Consequently, it appears that evidence provided

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Workpapers, pp 5-14.

[124] Ex. PG&E-39, (Rebuttal Testimony) pp. 4A-48 to 4A-51.

[125] 17 RT 1736:15-26 (Barnes/PG&E) ("And so what we see is in 2014, quite a few -- we were attacking, if you will, quite a few what we call shorts. So mini projects, short in length, as opposed to most of the projects leading up to 2013 were -- were less projects much longer in length. So we actually had some efficiencies associated with the length of the project. So when we roll into 2014, what we now … know 2014 is the actual unit costs for 2014 has actually gone up to $1.2 million a mile.").

[126] 17 RT 1776:21-22 (Barnes/PG&E). See also 17 RT 1758:26 – 1759:4 (Barnes/PG&E).

[127] PG&E's witness identified "shorts" as "mini-projects, short in length." 17 RT 1736:17-18 (Barnes/PG&E).

[128] Ex. ORA-85, (PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson)), p. 3-41.

[129] Ex. PG&E-4 (Workpapers), pp. WP 4A-52 and WP 4A-53, review of "Length (ft) for 2015-2016 projects shorter than 600 ft. 2015: 10012; 2016: 30008; 2016: 10074 and 10146." Note that the 2015 project number 10012 is listed twice, potentially indicating one project has two test sections, one 28,722 ft long and one 30 ft long. Projects 10009 and 10018 in 2015 and project F-97 in 2016 are shorter than 1,000 ft.

by PG&E contradicts PG&E's claim that the GT&S Hydrotest Program will contain enough shorts to result in "upward cost pressures."

Given that the evidence shows that the higher costs PG&E claims it experienced in 2014 were anomalous based upon the specific type of work performed in that year ("shorts"), and that this type of work will not recur in 2015-2016, it was therefore reasonable for ORA's 2015 forecast to rely on recorded 2011-2013 data, and exclude 2014 data as "anomalous."[130]

7.4.3.2 PG&E Should Continue To Experience Falling Hydrotest Costs Into And Beyond 2015 As A Result Of Efficiency Gains

ORA's witness testified that other information obtained through discovery or through his personal experience working on PG&E and Sempra utility pipeline programs since 2011 supported his conclusion that PG&E's hydrotesting costs should continue on a downward trend, including the following:

1. PG&E initiated the hydrotest program in 2011 in response the San Bruno explosion and the NTSB investigation that followed. It rightfully should have focused on safety, with less concern for the costs of the program. By 2015, PG&E should have progressed beyond "firefighting" mode and be positioned to make cost reduction more of a priority than previously.

2. PG&E implemented a hydrotest program cost reduction program in 2012, and there is no evidence that this program, or its successor, will fail to continue to produce cost reductions.[131]

3. 88% of the total hydrotest costs since the inception of PSEP were recorded by four "Alliance Construction contractors."[132] Pricing or cost containment was not a major factor in the selection of these contractors,[133]

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[130] See also Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 23, footnote 64; and Ex. ORA-108 (PG&E Response to ORA-92 Q12).

[131] See Ex. ORA-111 (PG&E Response to ORA-DR-59 Q23 A1).

[132] "The Alliance Construction contractor delivery model" and its progress is discussed in chapter 3 of each PSEP Report. See, e.g., Ex. ORA-92 contains the first two reports for 2014. In 2013, PG&E engaged in four contracts with "Alliance Construction contractors" and these contractors performed 218 of the 255 PSEP hydrotests performed from PSEP inception through March 31, 2014 2014. See Ex. ORA-81 (Redacted Attachment 1 to PG&E Response to ORA-DR-89 Q2) and Ex. ORA-79, Narrative of Workpapers, pp 22-23.

[133] See Ex. ORA-81 (Redacted Attachments 1 and 2 to PG&E's response to ORA 109 Q2).

cost control was not one of the primary objectives of the program,[134] and the "job estimate" for each project was determined by collaboration between PG&E and each Alliance contractor rather than through a project-level competitive solicitation.[135]

4. PG&E has multiple options going forward to utilize contracting methods with a greater focus on cost reduction, including adjusting the priorities with the current Alliance contractors model, re-negotiating those contracts, performing more work with PG&E construction crews, or utilizing the competitive solicitation process for more individual projects, or groups of projects.

5. Management of the large volume of water required for each hydrotest, which was the largest cost driver in Sempra's PSEP application (approximately 70%), provides a significant opportunity for cost reduction.[136] PG&E currently leaves water management to the construction contractors rather than treating water management as a significant cost driver and working with state agencies to find strategic ways to reduce both water supply and disposal costs.[137] Currently, PG&E does not collect data that allows it to quantify the actual cost of water management.[138] Consistent with ORA's recommendations in the Sempra PSEP case, PG&E should develop a water management plan focused on reducing water management costs, and seek CPUC assistance to work with other state water agencies to streamline permitting processes for the public good.[139]

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134 Ex. ORA-92 (April 30, 2014 PSEP Report, p. 11.) The stated "primary objectives" of this program are "the establishment of best-in-class safety performance, a robust construction delivery model, and the maintenance of a qualified/skilled workforce to perform work planned.").

135 Ex. ORA-81 (PG&E Redacted Response to DR-ORA-109 Q2b).

136 Ex. ORA-90 (ORA Exhibit 3, Revised Testimony of ORA Witness Roberts dated August 30, 2013 in the Sempra Utilities PSEP case, A.11-11-002) p.III-11.

137 Ex. ORA-80 (PG&E Redacted Response to DR-ORA-59 Q19).

138 Ex. ORA-80 (PG&E Response to DR-ORA-59 Q2g and Q2n).

139 Ex. ORA-90 (ORA Exhibit 3, Revised Testimony of ORA Witness Roberts dated August 30, 2013 in the Sempra Utilities PSEP case, A.11-11-002) pp. V-28 to V-29. Sempra requested CPUC assistance in its PSEP application and ORA supported this request. PG&E has hydrotest waste management procedures, provided as Redacted Attachments 1 and 2 to PG&E Response to ORA 59 Q17 (Ex. ORA-81), but these are project level procedures rather than a program-wide plan to strategically reduce water management costs including water supply, transportation, on-site storage, on-site treatment, and disposal.

6. A map of project locations provided by PG&E suggests that PG&E may not have considered the savings in mobilization/demobilization costs that could be achieved by performing tests in the same geographic area sequentially.[140] For example the map shows five tests in the Redding area, two in 2015, one in 2016, and two in 2017.[141] A review of PSEP hydrotest data indicates that most projects, even the longest tests, were completed in one to two months. Thus, it is unlikely that these five tests will require test equipment in one area for three years. Consideration of mobilization/demobilization costs in the scheduling of projects, which were estimated to be $500,000 per test in PSEP and claimed to be higher in the current application,[142] could result in considerable cost savings.[143]

Based on these findings, ORA's witness concluded that it was reasonable to assume that the cost reductions in hydrotest unit costs that PG&E has achieved to date can and should continue into the future.

PG&E offers no meaningful rebuttal to this ORA testimony. Instead, PG&E challenged ORA's regression analysis with two claims: (1) ORA should have included 2014 data, as this would have shown rising costs for that year and (2) ORA did not include total PSEP hydrotest program costs in its analysis. For the reasons discussed just above ORA does not believe that PG&E's 2014 "short" costs are representative of the costs that it will experience in the rate case years.[144] Consequently, it appropriately excluded them from its regression analysis. Similarly, PG&E's claims regarding ORA's failure to include "extra" hydrotest program costs in its analysis have no merit, for the reasons discussed in Section 7.4.4 below.

PG&E has also not sought CPUC assistance in this statewide issue. See Ex. ORA-80 (PG&E Response to ORA-DR-59 Q19e).

140 Ex. ORA-81(PG&E Response to DR-ORA-93 Q10, A1).

141 Refer to Table 11-1 in any of the PSEP Reports and compare the mobilization date, the starting date, to the tie-in date, the completed date.

142 See Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts),, p. 17 regarding PG&E's claims that increased mobilization/demobilization costs led to hydrotest costs higher than forecasted.

143 See Ex. ORA-85 (PG&E PSEP Testimony, Hogenson), p. 3E-15, and Ex. PG&E 1 (Direct Testimony, Chap. 4A, Barnes), p. 4A-40.

144 See Note 129 above.

7.4.3.3 PG&E's Workpapers Establish That Its Rate Case Period Hydrotests Will Be Significantly Longer Than Those Performed In 2013, Thus Resulting In Cost Reductions Through 2017, And Not The Upward Cost Pressures That PG&E Has Testified To

PG&E's witness testified that hydrotests completed in 2014 were shorter compared to those completed in 2013.[145] He confirmed that "shorter hydrotest projects generally have higher unit costs and longer hydrotest projects have lower unit costs."[146] However, he also argued that this principle regarding the impact of length on unit costs was irrelevant regarding GT&S. He repeatedly emphasized that the evidence of higher cost "shorts" in 2014 demonstrated that PG&E was "actually more likely going to be having upward pressures and pushing in that direction" and that it would be difficult for PG&E to keep its costs down to its forecast of $970,000 per mile.[147] He repeatedly re-stated this proposition:

> … PG&E is making a valid commitment to keep the costs as low as possible and therefore believe and continue to believe that $970,000 a mile is reasonable and achievable considering, taking into account escalation of course.[148]

And when asked whether longer hydrotests resulted in lower unit costs relative to the 2015 forecast he replied:

> No, I don't believe so. I think if you move farther down [the PG&E workpapers showing each of the projects proposed for 2015-2017], again, I think this represents the idea that we have many shorts that we have to do. We have cost pressures in the earlier years that are going to be more similar to 2014 costs of $2.1 million a mile.[149]

"Repetition does not transform a lie into a truth."[150] In this case, the evidence shows that there are very few "shorts" projected for the rate case period, that project length will, in fact,

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[145] 17 RT 1750:19-24 (Barnes/PG&E).

[146] 17 RT 1751:15-26 (Barnes/PG&E).

[147] 17 RT 1752:1-8 (Barnes/PG&E).

[148] 17 RT 1753:19-25 (Barnes/PG&E). See also 17 RT 1759: 21 – 1760:1 (Barnes/PG&E).

[149] 17 RT 1758:26 – 1759:4 (Barnes/PG&E).

[150] Franklin D. Roosevelt, Radio Address, October 26, 1939, 32nd President of United States.

increase annually during the rate case period, and that the cost pressures on PG&E will be *trending downward, not upward.*

The record shows that the average length of 2013 hydrotest projects was 2.5 miles.[151] The average length was expected to drop to 2.0 miles in 2014,[152] presumably as a result of the many "shorts" PG&E's witness described.[153] *PG&E's workpapers at Ex. PG&E-4 show that the average length of the projects it proposes for each year of the rate case period all exceed the 2013 average length of 2.5 miles*. The average length will be *2.67* miles in 2015, *3.51* miles in 2016, and *4.19* miles in 2017.[154] The growing per project length is clearly evidenced in PG&E's workpapers by the fact that PG&E proposes a hydrotest target of 170 miles per year, but the number of projects performed each year drops significantly, from 64 projects in 2015, to 48 in 2016, to 41 in 2017 – the point being that if the number of miles being tested does not change (it is always close to 170), but the number of projects is reduced, the average length of each project must necessarily be getting longer.[155] In fact, the length of the average hydrotest will increase by over 67% from 2.5 miles per project in 2013 to 4.19 miles per project by 2017.

As confirmed by PG&E's witness, an increase in length should result in significantly reduced unit costs.[156] By way of comparison, consider that a decrease in hydrotest length from

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[151] Ex. ORA-80, PG&E Response to DR-ORA-92 Q12.

[152] Ex. ORA-80, PG&E Response to DR-ORA-92 Q12.

[153] 17 RT 1751: 15-18 (Barnes/PG&E) ("Q So that's showing the increase in costs in 2014 as a result of the shorter hydrotest projects; is that correct? A That's correct.").

[154] ORA used standard MS Excel formulas to electronic version of PG&E Chapter 4A Workpapers in Ex. Indicated Shippers-70, specifically the data in at Ex. PG&E-4, pages WP4A-52 and 53, to establish the following statistics:

	2015	2016	2017
Projected Total Length, miles (=Sum)	170.972	168.426	171.990
Number of Projects per year (=Count)	64.0	48.0	41.0
Average Length, miles (=Average)	2.67	3.51	4.19

[155] 17 RT 1757-1758 (Barnes/PG&E). As shown in the previous footnote, PG&E's proposed projects per year vary only slightly from the 170 mile target.

[156] 17 RT 1751: 19-26 (Barnes/PG&E) ("Q Okay. So one of your points here is *that shorter hydrotest projects generally have higher unit costs and longer hydrotest projects have lower unit costs*; is that

2.5 miles per project in 2013 to 2.0 miles per project in 2014 led to an increase of $0.23 million per mile using PG&E's own unit cost numbers.[157]

PG&E projected in PSEP that for hydrotests, fixed costs are very high relative to variable costs, such that the cost per foot decreases with project length for all but the longest projects.[158] For example, for hydrotesting of 24" pipes PG&E forecasted fixed costs per project of $925,000 and variable costs of $45 per foot such that variable costs don't equal fixed costs until project length exceeds 3.9 miles.[159] Applying this PSEP forecast cost information to calculate the unit cost difference between 2.5 miles in 2013 and 4.19 miles in 2017 shows that the increase in project length results in a *25% decrease* in unit costs, from $0.607 million to test 2.5 miles to $0.458 million to test 4.19 miles.[160] Thus, PG&E's claim that the high cost for "shorts" in 2014 illustrates "upward cost pressure" is patently wrong. As ORA has show, planned GT&S hydrotest projects include only four projects shorter than 600 feet – thus there will be few shorts in the GT&S period. And because the average length of projects will increase from the 2.5 mile average length experienced in 2013, PG&E will experience *downward*, rather than *upward* cost pressures over the rate case period.[161]

Further, given that its workpapers so clearly evidence the trend of longer project lengths, PG&E should have known that the result would be downward pressure on unit costs when it proposed its forecast. Yet when presented with this trend, PG&E's witness answered "… I

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correct? A Yes, it is correct, based on my earlier conversation with you or earlier testimony.") (emphases added).

[157] $1.2 million per mile in 2014 less $0.97 million per mile in 2013.

[158] Ex. ORA-85 (PG&E PSEP Prepared Testimony in R.11-02-019, (Hogenson)), p. 3E-16. Consider also the analysis provided in Section 7.6.5.2 below.

[159] $925,000/ (45 $/ft)* (5280 ft/mile) = 3.9 miles.

[160] Unig the 2.5 mile average project length for 2013, the unit cost is ((2.5 miles*(5280 ft/mile)*$45/foot)+ $925,000)/2.5 miles) = $.607 million. Using the 4.19 mile average project length for 2017, the unit cost is ((4.19 miles*(5280 ft/mile)*$45/foot)+ $925,000)/4.19 miles) = $.458 million.

[161] As discussed in Section 7.6.5.2, pipe replacement projects have a different relationship between fixed and variable costs since it is much more expensive to excavate every inch of pipe to replace it, rather than just excavating the ends to hydrotest it. The result is that unit costs are relatively stable for all but the shortest replacement projects.

haven't done the math ..."[162] and reiterated the assertion that PG&E will experience upward, not downward, cost pressures.[163] Under continued cross examination, PG&E's witness continued to be unforthcoming. He responded: "I can certainly see your misconception here" and reiterated his statement regarding the challenge PG&E faces in meeting its forecast of $970,000 per mile.[164] However, he offered no evidence of upward cost pressures, other than the now disproven 2014 "shorts," nor did he challenge the fact that hydrotests would be getting longer over the rate case period.

7.4.3.4 PG&E's Decision To Ignore Evidence Of Declining Costs Shows That Its Forecast Is Unreasonable

PG&E claimed to have available to it a "rich data set of costing" to develop its "programmatic" forecast for 2015, and it did – including actual hydrotest costs for 2011 and 2012 and 2013. Thus, its decision to use only 2013 projects – informed mostly by forecasted costs – is curious. On cross examination, PG&E's witness attempted to explain PG&E's rationale for ignoring the "historical costs" from 2011 and 2012 available to it. In sum "2013 represented the lowest and most efficient that we had gotten the hydro static testing program,"[165] and 2014 included a number of "mini projects, short in length" resulting in actual 2014 unit costs of $1.2 million a mile."[166] He provided no specific information about the 2011 and 2012 costs, but argued that the 2014 data showed that PG&E would encounter rising cost pressures, even though those higher costs were clearly the result of shorter projects with higher costs – the "clean up" projects that followed the bulk of the PSEP work. On this basis – looking at the 2013 and 2014 data - he reasoned that PG&E's use of only 2013 data – even though a mix of forecast and actual data – was reasonable.

It might make sense to use only 2013 data if the work PG&E performed in 2013 were similar to (or representative of) the work PG&E expects to perform in 2015, and if the 2011 and 2012 work was anomalous, like 2014, which included short projects that drove up costs for that

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[162] 17 RT 1758:14-19 (Barnes/PG&E).

[163] 17 RT 1758:22 – 1759:9 (Barnes/PG&E).

[164] 17 RT 1759:10 – 1760:1 (Barnes/PG&E).

[165] 17 RT 1735:21-23 (Barnes/PG&E).

[166] 17 RT 1736:12-26 (Barnes/PG&E).

year. However, there is no evidence that the hydrotest work performed in 2011 and 2012 was meaningfully different from the work performed in 2013 – except that PG&E became more efficient over time, thus reducing costs. And PG&E does not suggest that the work performed in 2013 is more representative of the work planned for 2015, than the 2011 and 2012 work.

In fact, there is simply no basis for PG&E not considering the 2011 and 2012 actual cost data, other than PG&E's assertion that it was higher cost, and therefore shouldn't be considered. Further, PG&E's witness explained that PG&E did not believe that 2013 and 2015 were "the same."[167] Rather, he clarified that two factors drove the comparison between 2013 and 2015: (1) the scope of work – specifically the number of miles tested;[168] and (2) the fact that the 2013 forecast was the lowest unit cost PG&E had experienced.[169] Ultimately, PG&E's witness repeatedly affirmed that PG&E's determination to use only 2013 data was not based on anything other than the fact that $970,000 per mile was the lowest of a three year trend of falling costs:

> …[T]he $970,000 a mile was strictly based on the -- the large scale examination of what our unit costs would be for the forecasted period of time based on a combination of actuals and forecasts for 2013 because 2013 represented the lowest and most efficient that we had gotten the hydro static testing program.[170]

In presenting this simplistic analysis, and implying that PG&E's forecast was "reasonable" because it excluded higher cost data from 2011, 2012, and 2014, it is evident PG&E hoped the Commission would take its forecast at face value – and look no further. It is also evident that PG&E made a strategic decision not to look further itself, so that competing evidence would be difficult to adduce against it.

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[167] 17 RT 1749: 1-6 (Barnes/PG&E) ("We're not trying to say that 2015 and 2013 are the same. We're trying to say that the lowest cost per mile that we can identify is $970,000 per mile. So it's not really about them being the same.").

[168] 17 RT 1748:17-19 (Barnes/PG&E) (We're more looking at it from the perspective of the number of miles is similar in what we're trying to put forth."). See also Ex. ORA-109 (ORA DR-123 Q13) and 17 RT 1749:25 – 1750:4 (Barnes/PG&E) ("[Q The 2015 forecast was similar to the 2013 portfolio of projects. A portfolio of projects is determined by number of miles in projects, not by scope and type of hydrostatic test project. So is that what you meant when you just described -- A Yes.").

[169] 17 RT 1748:17-26 and 1749: 1-8 (Barnes/PG&E).

[170] 17 RT 1735:16-23 (Barnes/PG&E). See also 17 RT 1737:6-10 (Barnes/PG&E) ("I actually believe based on the data that we now know and the efficiencies we've now built into the process that $970,000 a mile is a very reasonable expectation for this program.") and 17 RT 1748:17-26 and 1749: 1-8 (Barnes/PG&E).

The record shows that PG&E's witness had an almost intentional ignorance of the Hydrotest Program and the forecast that was developed to fund it. He was not responsible for managing the Hydrotest Program.[171] He knew *virtually nothing* about the specifics of *any* of the work performed between 2011 and 2013,[172] and he could make no comparisons between that work and the work to be performed in the GT&S Hydrotest Program.[173] The only clarity he could provide regarding the Hydrotest Program forecast – other than the fact that using 2013 data produced the lowest number yet – was that PG&E did not believe that comparing the type of work performed in one year against the type of work performed in another year was relevant to

[171] 17 RT 1719:2-7 (Barnes/PG&E) (Q So in your position at PG&E, are you overseeing PG&E's hydro testing and pipeline replacement programs? A I am not overseeing the implementation of the work. I am sponsoring the testimony.").

[172] For example, while Mr. Barnes testified in his Direct and Rebuttal Testimony that mercury cleaning and water management costs (among others) produced highly variable costs that contributed to higher than forecast PSEP costs (Ex. PG&E-39 (Rebuttal Testimony), p. 4A-44 and 4A-45 and Ex. PG&E-1 (Direct Testimony), p. 4A-40: 3-11.), he could provide *no details* about these PSEP costs incurred during PSEP implementation, or what PG&E was doing to reduce those costs for GT&S. Discovery demonstrated that PG&E did not quantify these historic costs in any way. See Ex. ORA-110 (PG&E Data Responses to ORA DR-123). And when PG&E's witness was questioned regarding the basis for his assertions that these costs exceeded PSEP forecasts, he could not provide any rational explanation for the claims made in his testimony. See 17 RT 1773:18 – 1774:9. See also generally 17 RT 1763:27 – 1170:27. See e.g., 1769:14 – 1770:18 ("And you're saying that even though PG&E ... hasn't quantified any of these costs in [PSEP] … mercury cleaning, water management, excavating taps, serving the taps with CNG and LNG. PG&E hasn't quantified the actual costs of those. But they know that those are costs drivers nonetheless and that those costs have gone up? …. A I cannot validate one way or the other whether the team that's actually doing the hydrostatic testing has actually gone to the level of detail to analyze that information. I presume so because of what I saw in rebuttal testimony. But what I'm telling you is that *I didn't use that information*. We used the information that was related to the fact that we have an appropriate assessment that's pretty common when you have large quantities of work to spread the unit costs across the program to come up with a programmatic approach and programmatic value that seems to work."). Asked how he could make the claim in his testimony that these costs were so much higher than predicted, given that PG&E did not quantify these costs, he reverted back to his programmatic argument: 17 RT 1773:18 – 1774:24 (Barnes/PG&E).

[173] For example, consider PG&E's witness's ignorance of the length of 2013 hydrotest projects compared to PG&E's GT&S proposal, as described in Section 7.4.3.3 above. Consider also that when asked about water management for the GT&S projects, with a goal to understanding PG&E's opportunities for cost savings or cost avoidance - PG&E's witness could not answer whether PG&E had already taken efficiency steps such as coordinating with permitting agencies so that permits can extend to more than one project. 21 RT 2331:21 – 2332:1 (Barnes/PG&E). He was also unable to answer questions about mercury concentration maps provided by PG&E in response to ORA data requests (Ex. ORA-135). For example, he could not state for GT&S whether reduced mercury contamination (and therefore less cleaning) was anticipated in areas marked in green, and the converse for areas marked in red. 21 RT 2333:10 – 2335:27 (Barnes/PG&E).

informing its forecast, when it had four years of data to look at. In other words, it was irrelevant to the forecast if PG&E incurred more expensive mercury cleaning projects in one year, but not another.[174]

PG&E's rationale for using only 2013 data is neither logical nor credible. To better understand how more data would impact PG&E's Hydrotest Program forecast, ORA calculated unit costs using the programmatic methodology advocated by PG&E; but ORA used only actual cost data – and lots of it. ORA found that using data from all projects completed in 2013 results in a 2013 unit cost of $0.72 million per mile, significantly less than PG&E's $0.97 million per mile forecast. Even 2012, a supposedly higher cost year, produced a unit cost of $0.84 million per mile – still less than PG&E's 2013 forecast. The table below captures ORA's comparative analysis, which was presented in ORA's Direct Testimony.

Table 4C-4 from Ex. ORA-34, p. 20

Comparison of Recorded Costs From PSEP Reports

To Costs Represented By PG&E in GT&S

	Recorded Data from PSEP Reports						PG&E GT&S Request				
	Project Count	Total Footage	Total Mileage	Actual Cost ($million)	Unit Cost ($M/mile)		Miles Strength Tested	Cost ($million)	Unit Cost ($M/mile)		Unit Cost Variance (%)
2011	90	862,260	163.3	$ 195.4	$ 1.20		163	$ 231	$ 1.42		18%
2012	81	930,466	176.2	$ 147.4	$ 0.84		176	$ 179	$ 1.02		22%
2013	81	1,049,259	198.7	$ 143.0	$ 0.72		195	$ 190	$ 0.97		35%

Like PG&E, ORA did not calculate unit costs using data from projects completed in 2014. It made this decision based on the fact that the 2014 data included "crude and opaque" cost estimates, the availability of data was limited, and PG&E itself admitted that hydrotesting in 2014 was challenging and had higher unit costs.[175] Further, as discussed in Section 7.4.3.3 above, the record shows that PG&E's hydrotest projects will grow increasingly longer over the rate case period, thus reinforcing the point that 2014 was an anomalous year of "shorts" that will not be repeated during the rate case period.

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[174] See, e.g., Note 118 above.

[175] Ex. ORA-34, p. 23, footnote 64.

Unlike PG&E, ORA recognized that there was a clear trend of falling hydrotest costs (see Table 4C-4 above: $1.2 million per mile in 2011, $840 thousand per mile in 2012, and $720 thousand per mile in 2013), and that it was likely to continue for a number of reasons, as articulated in ORA's Testimony, and in this Section 7.4.3. Consequently, ORA performed a regression analysis to identify how those trends should impact 2015 hydrotest costs. Based on that analysis, ORA concluded that $0.56 million per mile was a reasonable unit cost forecast for 2015.

7.4.4 PG&E's Hydrotest Program Forecast Is Padded With Extra PSEP Costs That PG&E Did Not Report In Its Quarterly PSEP Compliance Reports In Violation of D.12-12-030.

7.4.4.1 The PSEP Decision Ordered PG&E To Report All Actual PSEP Costs In Quarterly Compliance Reports

Given the massive scope and cost of the work required to rebuild PG&E's gas transmission system in the wake of the San Bruno explosion, D.12-12-030 (the PSEP Decision) authorized funding for PG&E to perform work on its gas transmission system mid-way between rate case cycles.[176] In overruling ORA and TURN objections to this deviation from the general rule against post-test year ratemaking, the Commission determined that PG&E should report *publicly* and *regularly* on its *actual costs* for the program. In reaching this determination, D.12-12-030 explained that PG&E's "massive investment program" would be "funded primarily by ratepayers" and that "substantial amounts of new data on in-service pipeline will be brought to light by the unprecedented number of pressure tests and pipeline replacement construction that will be performed in the upcoming years."[177] The Commission also emphasized the need to ensure that the PSEP expenditures "are clearly distinct from the funding and expenditures that have already been provided for in D.11-04-031 (in PG&E's 2011 Gas Transmission and Storage Proceeding, A.09-09-013)."[178]

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[176] D.12-12-030, p. 82 ("The events in San Bruno required that PG&E take immediate action."), Finding of Fact 15, p. 117 ("Generally, post-test year ratemaking is disfavored when a forecasted test year revenue requirement is used to set rates. "), and Conclusion of Law 6, p. 121 ("The scope and magnitude of the costs at issue in the Implementation Plan justify deviation from the general rule against post-test year ratemaking.").

[177] D.12-12-030, p. 86.

[178] D.12-12-030, p. 86.

The same argument could be made for ensuring that the PSEP funding and expenditures were clearly distinct from PG&E's GT&S requests. Understanding the complexities of utility accounting, and the ability of the utility to use those complexities to its advantage, the Commission recognized a need to have a publicly available stand-alone accounting for PG&E's PSEP program – and therefore ordered that PG&E submit Quarterly Compliance Reports to the Commission, and make them available to the parties and the public.[179] There is no question that the Commission intended for *all actual PSEP costs* to be made publicly available in the PSEP Quarterly Compliance Reports so that parties could compare those costs to what was authorized, and bring questions and/or concerns to the Commission's attention. As 12-12-030 explained:

> To keep the Commission, the parties, and the public informed of PG&E's progress and *actual cost experience*, we will require PG&E to file and serve compliance reports. Such reports shall include the information and be in form set out in Attachment D. The information required will include comparisons of *actual* versus authorized cost for each work project as well as *explanations of any significant deviations*. Schedule and prioritization changes will also be included. Parties may review this information and *may request such Commission action by motion as needed*.[180]

This unprecedented level of Commission-ordered cost transparency was necessary given the extraordinary costs to be incurred over the coming decade, to rebuild PG&E's transmission system. In short, the Commission established a system to enable interested parties to review and analyze all of PG&E's PSEP costs, in an organized format, and without discovery on the utility. And ORA took advantage of that Commission-ordered transparency, often reviewing and analyzing the Quarterly Compliance Reports, and even reporting concerns and/or observations regarding its findings to the Commission's Safety and Enforcement Division.[181]

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[179] D.12-12-030, COL 32, p. 125 and OP 10, p. 128 ("Pacific Gas and Electric Company must submit compliance reports on the schedule and including the information set forth in Attachment D to today's decision. Such reports shall be filed and served in this proceeding, with printed copies to the Directors of the Energy Division and the Consumer Protection and Safety Division.").

[180] D.12-12-030, p. 86 (emphases added).

[181] ORA Acting Director Joseph Como sent a letter dated October 22,2013 to Elizaveta Malashenko, Deputy Director of SED regarding ORA's Suggested Improvements to PG&E's Quarterly Compliance Reports.

7.4.4.2 PG&E Claims To Have Excluded Over $100 Million in PSEP Costs From Its Quarterly PSEP Compliance Reports

For this rate case, when ORA sought to develop its own "programmatic" forecast based on the actual costs of PG&E's PSEP hydrotest work, it used the data provided in the Quarterly Compliance Reports. And as a review of ORA's Direct Testimony reveals, ORA struggled to understand why PG&E's project cost data it used to develop its GT&S forecast appeared to be significantly higher than the costs provided in the PSEP Quarterly Compliance Reports.[182]

ORA learned for the *first time* in PG&E's Rebuttal Testimony to ORA's analysis, that PG&E claimed to have "additional" PSEP hydrotest costs that were not reported in its Quarterly Compliance Reports. Specifically, PG&E criticized ORA's cost-based programmatic analysis because ORA failed to include the following PSEP hydrotest costs, which were not included in PG&E's Quarterly Compliance Reports:

1. Costs associated with cancelled or deferred projects;
2. General hydrotest program costs; and
3. Over $2 million in costs incurred after individual projects became operational.[183]

In each case, PG&E provided cursory and non-sensical explanations for why the costs were not included in the Quarterly Compliance Reports. Costs associated with "cancelled" or "deferred" projects were not reported because the "PSEP Compliance Reports only show costs for completed hydrotest projects for the reporting time period."[184] While PG&E admitted that "[g]eneral program costs can be quite significant and are for essential duties performed in the Hydrotest program" it stated that "the PSEP Compliance Report does not include or report on general hydrotest program orders."[185] The over $2 million in costs incurred after a project became operational were not reported because "[c]ost data contained in the PSEP Compliance Reports are based on costs incurred up until the project has become operational."[186]

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182 See, e.g., Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts),), pp. 20-22.

183 Ex. PG&E-39 (Rebuttal Testimony, Chap. 4A, Barnes), pp. 4A-46 to 4A-48.

184 Ex. PG&E-39 (Rebuttal Testimony, Chap. 4A, Barnes), p. 4A-47:26-28.

185 Ex. PG&E-39 (Rebuttal Testimony), p. 4A-47:11-12 and 7-8.

186 Ex. PG&E-39 (Rebuttal Testimony), p. 4A-46:18-20.

For all of these costs, PG&E appeared to assert in Rebuttal Testimony that the costs contained in the Quarterly Compliance Reports are incomplete for showing PSEP actual costs because they "represent a point in time" which excluded costs incurred once the projects are operational.[187] Finally, at various times PG&E also suggested that the Quarterly Compliance Reports did not contain these costs because Attachment D only required "certain types of costs" to be reported on "by Commission requirement."[188] Thus, PG&E appeared to suggest that D.12-12-030 prevented it from reporting on these costs.

ORA focused on this issue of missing PSEP cost information in its Supplemental Testimony.[189] That Supplemental Testimony described how PG&E should have and could have included all programmatic costs within the reported project costs for hydrotesting.[190] The same arguments hold for pipe replacement projects. PG&E should have and could have included all programmatic costs, except for the PMO, within the PSEP Quarterly Compliance Report project costs.

In response to that Supplemental Testimony, PG&E argued that the Commission never intended for information in the PSEP Quarterly Compliance Reports to be used for forecasting, and that the data in the Quarterly Compliance Reports is focused on PSEP projects, and therefore not reflective of PSEP "program" costs. Specifically, PG&E claims that by using PSEP data in the Quarterly Compliance Reports to propose a forecast challenging PG&E's, "ORA misapplied the intent of D.12-12-030 and the resulting content of PG&E's PSEP Quarterly Compliance Reports, *which were never intended for forecasting*."[191] PG&E also explained that ORA's

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[187] Ex. PG&E-39 (Rebuttal Testimony), p. 4A-46:17-20.

[188] See, e.g., 18 RT 1865:16-25 ("… the PSEP compliance reports were developed at a certain level of detail per Commission requirement. And the details that are in them do not have certain types of costs that are being reported upon, again by Commission requirement."). Also see Ex. PG&E-48 (Rebuttal to ORA Supplement Testimony), p.4AS-3 "the data provided in response to Question 11 of Attachment D [to D.12-12-030] are project costs; they do not include all costs incurred to within the Hydrostatic Testing Program. Other costs exist outside of what is charged directly to a project, as further explained in PG&E's Rebuttal Testimony, page 4A-45 Q 128, line 123."

[189] Ex. ORA-47 (Supplemental Testimony).

[190] Ex. ORA-47 (Supplemental Testimony), pp. 12-13.

[191] Ex. PG&E-48 (Rebuttal to ORA Supplemental Testimony), p.4AS-2 (emphases added). While the comment is focused on ORA's Hydrotest forecast, it applies equally to ORA's VIPER forecast.

criticisms "reflect a *fundamental misunderstanding* of the data contained in the PSEP Quarterly Compliance Reports, and how they relate to PG&E's program data."[192]

7.4.4.3 PG&E's Arguments That It Was Not Required To Include All PSEP Actual Cost Data In Its Quarterly Compliance Reports Have No Merit

None of PG&E's explanations for excluding this alleged PSEP actual cost information from the Quarterly Compliance Reports have merit. As described above, D.12-12-030 clearly required that PG&E provide a public reporting of *all* of its PSEP actual costs – both those costs paid by ratepayers, as well as those absorbed by PG&E shareholders. To the extent that any of PG&E's costs were related to PSEP, they should have been reported in some fashion in the Quarterly Compliance Reports.

Attachment D to D.12-12-030 established the framework for reporting that information, and set out specific classes of costs that should be aggregated (to facilitate access to and understanding of the data). There is every indication in Attachment D that it fully intended to include *specifically* the type of information PG&E excluded in this instance. Regarding cancelled or deferred projects, Attachment D stated: "Describe or provide a specific reference to PG&E's work papers of the projects that were not completed or replaced by a higher priority project and show the uncompleted project's associated costs."[193] Certainly, it is no stretch to conclude that costs associated with "cancelled" or "deferred" projects should be included in the category for "projects that were not completed."

Similarly, general hydrotest program costs that were not disclosed as Program Management Office costs under Item 7 of Attachment D, or included in specific project costs, should, at a minimum, have been quantified and disclosed in some manner pursuant to one of the many Attachment D catchall provisions, including Items 11, 17 through 21, 27, or 28. For example, general costs should have been included in Table 11-1 of the PSEP Quarterly Compliance Reports in the "other" cost category – as observed in ORA's Supplemental

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[192] Ex. PG&E-48 (Rebuttal to ORA Supplemental Testimony), p. 4AS-2 (emphases added)..

[193] D.12-12-030, Attachment D, Item 26.

Testimony.[194] However, PG&E did not disclose these costs in any manner in its Quarterly Compliance Reports.[195] These costs showed up for the first time in PG&E's Rebuttal Testimony.

PG&E's rationales in its Rebuttal to ORA's Supplemental Testimony are similarly unpersuasive. As described above, PG&E argued that D.12-12-030 "never intended" the Quarterly Compliance Reports to be used for forecasting."[196] However, nothing in D.12-12-030 suggests that the Commission did *not* intend for the PSEP Reports to be used for forecasting. In fact, D.12-12-030 is clear that the Commission was interested in having "PG&E develop better cost forecasting models."[197] Consequently, given the breadth of information required by Attachment D, it is fair to conclude that the requirement that PG&E prepare the Quarterly Compliance Reports was intended as a reasonable step towards achieving this goal.[198]

PG&E's claim that ORA had a "fundamental misunderstanding of the data contained in the PSEP Quarterly Compliance Reports, and how they relate to PG&E's program data"[199] is similarly unavailing. Evidently, PG&E believes it was only required to provide PSEP *project* cost data, and not necessarily all PSEP *program* data. Evidently, the Commission shared ORA's "fundamental misunderstanding" because it expressly stated that the PSEP costs adopted were for programs, not projects:

> The amounts [approved for rate recovery] in Attachment E are *program-based* upper limits on expense and capital costs to be recovered from ratepayers for the specific projects authorized through the implementation plan…"[200]

PG&E's various arguments and explanations for why it did not include all PSEP cost data in its Quarterly Compliance Reports have no merit. Given the plain language of D.12-12-030

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[194] Ex. ORA-47 (Supplemental Testimony), p. 12:17-24 and footnote 54.

[195] 18 RT 1865:26 – 1866:2 (Barnes/PG&E) ("So what we're representing here [in my Rebuttal Testimony] is that the cost that we used for looking at the total forecast included costs that are not contained in the PSEP quarterly compliance report."). See also Ex. PG&E-39 (Rebuttal Testimony, Chap. 4A, Barnes), pp. 4A-46 to 4A-48.

[196] Ex. PG&E-48 (Rebuttal to ORA Supplemental Testimony), p.4AS-2. While the comment is focused on ORA's Hydrotest forecast, it applies equally to ORA's VIPER forecast.

[197] D.12-12-030, p.100.

[198] See D.12-12-030, Attachment D, p. D2, requirement 11.

[199] Ex. PG&E-48 (Rebuttal to ORA Supplement Testimony), p. 4AS-2.

[200] D.12-12-030, p.120 (emphases added).

and Attachment D, it was reasonable for both the Commission and ORA to conclude that PG&E was ordered to provide all PSEP cost information in the Quarterly Compliance Reports, and not just project-specific information.

As such, PG&E is in violation of both D.12-12-030 and Rule 1.1 of the Commission's Rules of Practice and Procedure for failure to provide this information in its Quarterly Compliance Reports. This oversight should be corrected.

7.4.4.4 PG&E's Total of Over $100 Million In Unreported PSEP Costs Demonstrates The Unreasonableness Of PG&E's Hydrotest Program And The Need For A Commission Audit of Both PSEP and GT&S Expenditures

In response to ORA discovery, PG&E finally quantified its alleged and unreported PSEP actual costs of over $100 million as follows:

1. Costs associated with cancelled or deferred projects: $39.167 million;
2. "General hydrotest program costs": $62.824 million; and
3. Costs incurred after individual projects became operational: "over $2 million."[201]

However, PG&E's data supporting these over $100 million in previously unreported PSEP costs was inconsistent, contained irregularities, and did not support PG&E's GT&S forecast. Consequently, ORA was required to produce Supplemental Testimony to address the data PG&E produced and to describe the deficiencies in that data. In sum, ORA explained those deficiencies as follows:

1. A significant portion of PG&E's claimed $62.8 million for "general hydrotest program costs" could not be verified because the cost data were lumped together under vague headings such as "Strength Test – Program." Further, the majority of the "general" costs appear to have been incurred during the 2011 PSEP start up period. This and other factors suggested that the majority of the general costs were unique to PSEP and unlikely to occur during GT&S;[202]

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[201] Ex. ORA-120 (PG&E Response to ORA-DR-123 Q9, Q10, and Q11).

[202] Ex. ORA-47 (Supplemental Testimony, Chap. 4A, Roberts) pp. 2 and 13-18. See specifically p. 16 lines 35-42 and p. 18 lines 27-30 ("If costs in the 22 general cost orders were found to be reasonable for PSEP, it is probable that they would also be found to be one-time start up costs that are unique to PSEP, and not likely to be incurred for the ongoing continuation of the hydrotest program in GT&S. The GT&S forecast should only include costs that are likely to be incurred on an ongoing basis, and PG&E has failed to meet its burden of proving this.")

2. PG&E's claimed $39.167 million in PSEP costs related to cancelled and deferred projects resulting from found records was excessive and inappropriate for use in the GT&S forecast because, among other things, GT&S should not experience this level of cancelled projects as a result of newly discovered records;[203]
3. Inconsistencies and irregularities in the data provided by PG&E raised questions about the accuracy of the data PG&E relied upon to support both its unreported PSEP costs, and its GT&S forecast generally;[204] and
4. PG&E's claim of "over $2 million" in costs incurred after certain projects were operational was unsupported by the data and in any event, understatement of such costs was more than offset in ORA's forecast by the use of higher reported PSEP costs.[205]

Based on this review of PG&E's supporting data, ORA did not revise its GT&S Hydrotest Program forecast to include these unreported PSEP costs.[206] For the same reasons, PG&E's 2013 unit cost forecast should be rejected.[207] ORA's calculation of a unit cost of $0.72 million per mile for 2013 is based on PSEP data reported pursuant to D.12-12-030, and its calculation of $91.72 million should be adopted as a reasonable programmatic forecast of what PG&E's GT&S Hydrotest Program will actually cost during the rate case period.

7.4.4.5 An Audit Of PG&E's PSEP Accounting And Expenditures Is Warranted

Finally, ORA's Supplemental Testimony observed that the magnitude of PG&E's PSEP and GT&S expenditures, and the irregularities and inconsistencies in the data sets provided by

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[203] Ex. ORA-47 (Supplemental Testimony, Chap. 4A, Roberts) pp. 4-11.

[204] Ex. ORA-47 (Supplemental Testimony, Chap. 4A, Roberts) *passim,* but see specifically pp. 2, 9-11, 17-18 and 20-23.

[205] Ex. ORA-47 (Supplemental Testimony, Chap. 4A, Roberts) pp. 2 and 19-20.

[206] Ex. ORA-47 (Supplemental Testimony, Chap. 4A, Roberts) p. 2:26-28 ("It is important to note that I excluded these costs from ORA's GT&S cost forecast primarily because of differences between the PSEP and GT&S programs, independent of whether costs were or were not reasonably and correctly recorded as PSEP costs.")

[207] Further, in a repeating theme regarding PG&E's support for its Hydrotest and VIPER Program forecasts, cross examination of PG&E's witness on its unreported PSEP costs revealed an astounding lack of knowledge regarding the costs and data behind both his initial Rebuttal to ORA's Testimony (Ex. PG&E-39), as well as his Rebuttal to ORA's Supplemental Testimony (Ex. PG&E-48). See, e.g, 18 RT 1868:5 – 1870:11 wherein the witness was uncertain or didn't know at least 4 times. On this basis alone, PG&E's testimony on these issues should be given little weight.

PG&E, demonstrate the need for the Commission to: (1) order PG&E to update its Quarterly Compliance Reports with *all* actual cost information; and (2) require an audit of the reasonableness of PG&E's PSEP and GT&S expenditures.[208] This type of oversight will provide invaluable information for future forecasts and will ensure that ratepayers are getting the full value of what they are paying for.

7.4.5 Hydrotest Costs For Post-1955 Lines Should Be Disallowed Consistent With D.12-12-030

7.4.5.1 Consistent With D.12-12-030, PG&E Should Pay For All Hydrotests Performed On Pipes Installed After 1955 Because Ratepayers Already Paid Once For This Work

One of the primary concerns revealed by the San Bruno incident has been PG&E's lack of records and proper record-keeping and maintenance associated with its natural gas system.[209] Every review of the contributing factors to the San Bruno incident has determined that PG&E's failure to maintain accurate records of its system contributed to that explosion.[210]

Decision 12-12-030 disallowed hydrotest costs for all post-1955 lines on the basis that PG&E pressure tested those lines at ratepayer expense and should have retained records of those pressure tests.[211] Nevertheless, PG&E proposes in this case to move the date for the commencement of disallowances from 1956 to 1961, when General Order (GO) 112 was adopted, on the basis that it was not required to perform pressure tests before GO 112 was adopted in 1961, and that it was "unlikely" the Commission would have allowed rate recovery for such activities as a result.[212] All of these issues were resolved in D.12-12-030 such that PG&E's arguments are nothing but relitigation of issues already decided in D.12-12-030.

[208] Ex. ORA-47 (Supplemental Testimony, Chap. 4A, Roberts) pp. 2 and 20-23. Among other things, ORA's Supplemental Testimony reflects how the data PG&E claimed to rely upon for its GT&S forecast repeatedly changed over time. See specifically the text at p. 21 and Table 4C-S-7. ORA is not proposing that this audit would result in any ex poste adjustment of PSEP cost authorized by D.12-12-030 and D.14-11-023.

[209] See e.g., D.15-04-021 (Recordkeeping Investigation)

[210] See e.g., D.15-04-021 (Recordkeeping Investigation) and D.15-04-023 (Explosion Investigation).

[211] D.12-12-030, FOF 16-18 and 33-35 and COL 15-16.

[212] ORA supports PG&E's proposal that its shareholders pay the hydrotest costs for pipes installed after 1961 and lacking TVC hydrotest records (Ex. PG&E-1 (Direct Testimony, Chap. 4A, Barnes), p. 4A-42)

In this case, PG&E provides four reasons[213] why PG&E should not face continued disallowance of pressure test costs for pipe installed between 1956 and 1961:[214]

1. There were no requirements to hydrostatically test pipe when it was installed between 1956-1961;
2. At the time of enacting pipeline safety regulations, the Commission and federal government consciously chose not to require hydrostatic tests for pipe installed prior to that time;
3. The hydrostatic test provision in the American Standards Association (ASA) code was new and not widely applied in the industry, so it cannot be considered an established practice in 1956-1961; and
4. It was unlikely the CPUC would have provided rate recovery for hydrostatic testing activities in 1956-1961 given that it was not a requirement.[215]

The Commission rejected all of these PG&E arguments in D.12-12-030, which approved PG&E's PSEP. The Commission unequivocally found, based on the record in that proceeding, that PG&E stated that its practice from 1956 on was to pressure test pipeline prior to placing it in service,[216] that the costs of these pressure tests were passed on to ratepayers,[217] and that PG&E should have retained the records of these tests:

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but clarifies that the disallowance applies to pipes installed after June 30, 1961, which is the effective date of GO-112. See D.12-12-030, p. 11, footnote 9.

[213] PG&E originally made five arguments, but withdrew one in response to ORA's observation that it was wrong. PG&E then attempted to replace that argument with an additional new argument in errata (revising both its Direct and Rebuttal Testimony) that ratepayers should be responsible for these hydrotest costs because the American Standards Association (ASA) Code did not require a test duration during that period. See Ex. PG&E-46 (Errata Vol. 1), pp. ERRATA 43 and ERRATA 88-89. However, this argument was struck as an improper use of errata. 26 RT 3484:28 – 3486:5 (Rebuttal Testimony) and 31 RT 4294:13 – 4298:15 (Direct Testimony) (ALJ rulings granting motions to strike errata on the basis that errata cannot be used to introduce new arguments).

[214] PG&E does not dispute that it had an obligation to pressure test lines and retain the records of those tests after the adoption of General Order 112 in 1961. Ex. PG&E-1, p. 4A-42.

[215] PG&E Prepared Testimony, Volume 1 (Barnes), p. 4A-43.

[216] The San Bruno Recordkeeping Investigation (I.11-02-016) recently reached similar conclusions. See D.15-04-021, FOF 11 ("ASME B.31.8 contains specific recordkeeping requirements associated with the design, installation, operations and maintenance of transmission pipeline systems."); FOF 12 ("Although compliance with ASME B.31.8 was not required, PG&E stated that it voluntarily followed these standards."); FOF 46 ("Prior to 1961, pipeline operators in California voluntarily followed the ASME B.31.8 standards, which included standards for pressure testing for pipe after construction and before operation and the type of test to be performed."); FOF 47 ("ASME B.31.8 § 841.417 specified that records of these pressure tests were to be retained for the useful life of the pipeline."); and FOF 71 ("In 1955, PG&E represented to this Commission that it following the ASME B.31.8 standard.").

> We do not agree that the change from an industry practice to regulatory mandate somehow excuses PG&E's failure to retain the pressure test records. As noted above, the record supports the finding that PG&E stated that from 1956 on, PG&E's practice was to pressure … test pipeline prior to placing it in service and that the costs of such testing was passed on to ratepayers. As required by industry practice and prudent natural gas transmission system operations, PG&E should have created and maintained records of those pressure tests.[218]

Based on these findings, the Commission determined that PG&E's shareholders should pay hydrotest costs, or their equivalent, for all pipelines installed after 1955 that do not have traceable, verifiable, and complete (TVC) records. Thus, D.12-12-030 disallowed hydrotest expenses for post-1955 lines, and disallowed the cost of a hydrotest from post-1955 lines that were replaced, rather than hydrotested, because they did not have TVC records of the hydrotest.[219]

The Commission should not change this well-reasoned determination – which is based on substantial record evidence – by now pushing the date from 1955 to 1961, as PG&E requests. While the conclusions of D.12-12-030 should be dispositive on this issue, ORA addresses each of PG&E's arguments in support of moving the disallowance date to 1961. In sum, none of PG&E's arguments are new or have any merit; they were addressed and dismissed by the Commission in D.12-12-030.

7.4.5.2 PG&E's First, Second, And Third Arguments To Move The Hydrotest Disallowance From 1955 to 1961 Are Contradicted By PG&E's Own Statements To the Commission And Were Dismissed by D.12-12-030

PG&E argues that: (1) there were no requirements to hydrostatically test pipe when it was installed between 1956-1961; (2) at the time of enacting pipeline safety regulations, the Commission and federal government consciously chose not to require hydrostatic tests for pipe installed prior to that time; [and] (3) the hydrostatic test provision in the American Standards

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[217] D.12-12-030, FOF 18 and 35.

[218] D.12-12-030, p. 60. See also p. 61, FOF 18 and COL 16.

[219] D.12-12-030, Conclusions of Law 15 and 16.

Association (ASA) code was new and not widely applied in the industry, so it cannot be considered an established practice in 1956-1961.[220]

In sum, these arguments are based on the idea that because no state or federal law prior to 1961 specifically required PG&E to hydrotest its lines, PG&E had no obligation to do so and should therefore not be responsible for the costs of hydrotesting lines installed before 1961. These arguments have no merit and were dismissed by D.12-12-030 (and more recently in D.15-04-021, the San Bruno Recordkeeping Investigation)[221] in light of PG&E statements contradicting these arguments.

State or federal law or regulations prior to 1961 may not have specifically and expressly required PG&E to hydrotest its lines, but this is not relevant for a number of reasons. First, PG&E has had a statutory obligation to maintain and operate its system safely since 1909.[222] A gas transmission system cannot be operated safely without knowing the pressure tolerance of the lines comprising that system. Thus, conducting a pressure test and retaining the results of that test are critical to the safe operation of a gas transmission system.

Second, PG&E represented to the Commission at the time that General Order 112 was adopted (approximately 1961) that it *complied* with industry standards.[223] Thus, whether or not law or regulations required hydrotesting, PG&E represented to the Commission that it was nonetheless complying with industry standards – and those standards required pre-installation hydrotesting. In light of PG&E's reliance upon those standards, it is disingenuous and misleading for PG&E to now suggest that those standards were irrelevant. Further, evidence adduced in this proceeding demonstrates that PG&E has records for approximately 62% of the transmission pipeline installed between 1955 and 1961, thus supporting its prior claims that it

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[220] PG&E Prepared Testimony, Volume 1 (Barnes), p. 4A-43.

[221] See Note 216 above.

[222] D.15-04-021, p. 49.

[223] Ex. ORA-151 (Decision 61269) Decision 61269, issued December 28, 1960 and effective July 1, 1961, p. 4, adopting GO 112, describes the position of the respondents, PG&E and others: "… the gas utilities in California voluntarily follow the American Standards Association (ASA) code for gas transmission and distribution piping systems."

was complying with the industry standards.[224] It is fair to conclude, as D.12-12-030 did, that PG&E's demonstrated failure to maintain records is responsible for those that are missing.

Third, PG&E's suggestion that the hydrotesting standard "was new and not widely applied in the industry, so it cannot be considered an established practice in 1956-1961" is simply not supported by previous versions of the standards. Industry standards have recommended that gas pipelines be pressure tested since 1935.[225] Further, PG&E specifically represented to the Commission that it believed its practice was to follow the ASME standards regarding pre-service testing after the adoption of those standards in 1955.[226] On March 15, 2011, PG&E filed a report on MAOP validation in the PSEP proceeding, R.11-02-019. At page 13, the report showed that of the pipelines analyzed and installed before July 1, 1961, at least 31% were pressure tested.[227] In response to the question "[w]hat was the justification for performing these tests?" PG&E responded:

> Pressure tests were, and are, a means to confirm or test the strength of pipeline segments. PG&E believes that after adoption of American Society of Mechanical Engineers (ASME) standard ASA B31.1.8-1955, PG&E's practice was to follow ASA B31.1.8-1955, including pre-service testing.[228]

Given PG&E's repeated representations that it followed the standards of the time, its current claims that industry standards, absent mandatory laws or regulations, are irrelevant, or that they were not widely adopted by 1955 are not credible. When the Commission considered similar claims in D.12-12-030, it determined that PG&E was or claimed it was complying with hydrotesting standards starting no later than January 1, 1955, and concluded that a hydrotest disallowance on pipes installed post-1955 without TVC records was appropriate.[229]

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[224] Ex. ORA-174 (ORA Data Request to PG&E 147, Question 2 and Attachment 1).

[225] Ex. ORA-173, see ASA B31-1935 at pp. 55-56.

[226] Ex. ORA-113 (R.11-02-019, PG&E Response to DRA-DR-045 Q7).

[227] Ex. ORA-112 (MAOP Report).

[228] Ex. ORA-113 (R.11-02-019, PG&E Response to DRA-DR-045 Q7(a)).

[229] D.12-12-030, Findings of Fact 16, 17, and 18 and Conclusions of Law 15 and 16.

7.4.5.3 PG&E's Fourth Argument To Move The Hydrotest Disallowance From 1955 to 1961 Is Contradicted By Prior PG&E Statements To The Commission And Has No Merit

PG&E claims that "it was unlikely the CPUC would have provided rate recovery for hydrostatic testing activities in 1956-1961 given that it was not a requirement."[230] This argument is directly contradicted by PG&E's own statements to the Commission in 2011 in the PSEP proceeding, R.11-02-019. As a follow up to PG&E's representations that it had been performing pre-installation hydrotests on pipes since the adoption of the ASME hydrotesting standard in 1955, ORA asked: "Were these tests funded by PG&E ratepayers or PG&E shareholders?" to which PG&E responded "The testing was part of the pipe installation costs and, therefore, would have been funded by ratepayers."[231]

Indeed, the Commission relied upon this evidence to conclude that because ratepayers funded the original pre-installation hydrotests, it was unreasonable for them to pay for a second hydrotest required because of PG&E's records mismanagement.[232] D.12-12-030 further concluded: "[n]o evidence was presented that PG&E excluded the costs of pressure testing pipeline from its regulated revenue requirements from January 1, 1956."[233] Even without these clear contradictory statements from PG&E in other cases before the Commission, it would be unreasonable for the Commission to allow such costs to be passed on to ratepayers on the basis that the work was not required by law or regulation. As PG&E is well aware, the CPUC routinely authorizes utility work not expressly required by law or regulation, and ORA is fairly certain that PG&E would not support the imposition of such a Commission-policy going forward.

In conclusion, PG&E has failed to demonstrate why the Commission's determination in D.12-12-030 should be ignored and essentially modified. Therefore, its request should be denied and the holdings in D.12-12-030 affirmed.

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[230] Ex. PG&E-1 (Direct Testimony, Chap. 4A, Barnes), p. 4A-43.

[231] Ex. ORA-113 (R.11-02-019, PG&E Response to DRA-DR-045 Q7(f)).

[232] D.12-12-030, p. 60.

[233] D.12-12-030, Finding of Fact 18, p. 118.

7.4.6 ORA's Forecast Is Reasonable And Its Recommendation Of An $87.5 Million Reduction To PG&E's $179.2 Million 2015 Hydrotest Program Expense Request Should Be Adopted

ORA's forecast is reasonable because it is based on a programmatic analysis that uses three years of actual cost data reported in PSEP Quarterly Compliance Reports by PG&E, and it takes the evidence of falling hydrotest costs into consideration. In contrast, PG&E's forecast is based on one year of mostly forecasted cost data, contrary to PG&E's testimony that a programmatic forecast should consider "historicals,"[234] a "rich data set of costing,"[235] "actual costs,"[236] "look[ing] at those actuals,"[237] and reviewing a "relatively large amount of data"[238] in order to "spread all those -- all that variability over the program"[239] so that "you wind up with a program that -- that has a rational level of funding associated with it."[240] And PG&E ignores evidence that its hydrotest costs will fall significantly during the rate case period. Both of these decisions by PG&E result in a hydrotest forecast that, when viewed through the lens of PG&E's actual reported historical costs, is not "rational" and is significantly inflated.

Based on all of the foregoing discussion comparing the merits of the PG&E and ORA unit cost forecasts, ORA recommends adoption of its unit cost forecast for 2015 of $0.56 million per mile.[241] Using this forecast reduces PG&E's requested forecast by $78.8 million, and is consistent with ORA's analysis that shows that PG&E's hydrotest costs are falling, not increasing.

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234 19 RT 2122:21 (Barnes/PG&E).

235 19 RT 2122:21 (Barnes/PG&E).

236 21 RT 2344:8-15 (Barnes/PG&E) (Explaining to the ALJ his experience with ILI forecasting for El Paso).

237 19 RT 2121:24 – 2122:26 (Barnes/PG&E) (Responding to a question about the VIPER forecast, but explaining programmatic costs and his LI work at El Paso generally).

238 18 RT 1920:2-6 (Barnes/PG&E) (Regarding the VIPER forecast).

239 17 RT 1727:9 – 1728:8 (Barnes/PG&E) (Regarding programmatic forecasts generally and his ILI experience at El Paso).

240 17 RT 1727:9 – 1728:8 (Barnes/PG&E) (Regarding programmatic forecasts generally and his ILI experience at El Paso).

241 ORA notes that this unit cost is roughly consistent with the average unit cost of $.50 million per mile that PG&E forecast for PSEP in 2011.

ORA also recommends disallowance of expenses for pipe installed after 1955 where PG&E does not have traceable, verifiable and complete hydrotest records. Based on ORA's proposed unit cost of $0.56 million per mile and PG&E's estimate that 47 miles included in the Hydrotest Program were installed between 1955 and 1961,[242] this results in a $8.8 million disallowance.[243] Under PG&E's proposed unit cost, this disallowance would be $16.0 million.

In summary, application of ORA's forecast and the 1955-1961 disallowance results in $87.5 million adjustment to PG&E's 2015 hydrotest expense forecast of $179.2 million, to $91.72 million. Details regarding how this adjustment should be reflected in the Results of Operations Model are set forth in ORA's Testimony.[244]

7.5 Earthquake Fault Crossings

7.6 Vintage Pipe Replacement

7.6.1 Overview – PG&E's Forecast Is Unreasonable; ORA's Should Be Adopted Because It Uses The Programmatic Approach Advocated For By PG&E To More Accuately Predict PG&E's Actual Program Costs

PG&E estimates that there are 370 miles of pipe with "vintage features" in locations where there is a threat of land movement, and that these pipes represent "one of the top risks facing the transmission pipe asset."[245] PG&E proposes to replace 20 miles of this pipe that are *"in proximity to population"* during each year of the rate case period.[246] PG&E forecasts $193.8 million in capital costs associated with the VIPER Program in 2015 and $596.5 million for the rate case period.

PG&E's VIPER Program forecast is unreasonable because:

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[242] Ex. PG&E-1 (Direct Testimony), Table 4A-12, p. 4A-43.

[243] This disallowance should change if more than 47 miles are subject to this disallowance, or if the Commission ultimately adopts a different unit cost. Further, as described in Section 7.4.5.1 above, this disallowance should apply to line segments PG&E's elects to replace rather than hydrotest.

[244] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 30.

[245] Ex. PG&E-1 (Direct Testimony with Errata, Chapter 4A, Barnes), p. 4A-52 and 4A-55.

[246] Ex. PG&E-1 (Direct Testimony with Errata, Chapter 4A, Barnes), p. 4A-54 (emphases added).

1. Contrary to PG&E's claims that programmatic forecasts take advantage of large amounts of data to smooth out the variability in the costs of individual projects,[247] PG&E's VIPER Program forecast is based on a limited sample of nine PSEP projects which have not been shown to be representative of the typical projects in the VIPER Program;
2. PG&E asserts that its unit costs should be high because VIPER "is targeted on very short segments of pipe that are in congested locations,"[248] but provides no support for this assertion and there is evidence that VIPER projects will move to less congested areas during the rate case period and that any difference in length will have minimal cost impact;
3. PG&E's application seeks to double the pipe replacement costs adopted for PSEP, but provides no persuasive analysis to explain why its VIPER costs will be double the PSEP forecast adopted in D.12-12-030, and at least 50% more than the actual costs incurred in the PSEP program through 2013;
4. Assuming project costs as of 2012, PG&E incorrectly applied a three year escalation rate to all nine projects used in its VIPER forecast, even though some of the projects were completed in 2013 and 2014; and
5. PG&E's assertion that VIPER costs will increase during the rate case period is inconsistent with PG&E's request for a Project Management Office (PMO) to reduce VIPER costs.

PG&E attempted to address several of these ORA critiques in its Rebuttal Testimony, and through improper errata changes to its testimony, but as discussed in more detail in Section 7.6.13 below, it provided no meaningful evidence to rebut ORA's criticisms.

One of the primary distinctions between ORA's VIPER Program forecast and PG&E's is that PG&E's forecast is based on nine cherry-picked PSEP pipe replacement projects – at least three of which had forecasted, not actual, costs. It claims to rely on these nine projects because they are representative of the shorter projects that will be in the VIPER Program. In contrast, ORA's forecast is based on the actual costs of all 42 PSEP replacement projects completed in 2012 and 2013, without excluding projects based on assumptions of how VIPER might differ from PSEP. ORA's assumption that the work performed in the PSEP program will be comparable to the work performed in the VIPER program relative to unit costs is reasonable because:

[247] See Notes 47 and 81.

[248] Ex. ORA-80 (PG&E Response to ORA-DR-056 Q4a).

1. Both programs target highly populated areas;
2. Both programs will include non-HCA pipe segments where needed due to constructability and economics;
3. Both programs involve a mix of long and short projects, a vast majority of which are long enough that unit costs are not driven by fixed program costs;
4. ORA analysis shows that any program-wide differences in project length will have a small impact on unit costs; and
5. PG&E has not quantified any cost differences based on its perception that "Vintage Pipe Replacement Program is targeted on very short segments of pipe that are in congested locations." [249]

Each of these factors is discussed in detail in Section 7.6.12 below. In sum, PG&E's claims that VIPER projects are shorter and in more congested locations does not support PG&E's request for a VIPER budget twice the adopted PSEP budget and more than 50% higher than PSEP actual costs through 2013.

Applying the programmatic methodology advocated by PG&E, but using two years of actual cost data for 42 PSEP projects, ORA has determined that PG&E will incur no more than $110 million per year to implement its VIPER Program during the rate case period. In fact, PG&E's costs are likely to decrease over time so that adopting ORA's forecast will likely overcompensate PG&E in 2016 and 2017. ORA's forecast is also supported by multiple comparative analyses, including one water pipeline replacement in the San Francisco Bay area.

For these reasons, as more fully discussed below, ORA's forecast is reasonable and should be adopted.

7.6.2 PG&E's Application Provided Only Nominal Support For, And Explanation Of, How It Calculated Its VIPER Forecast

PG&E's Application provided only nominal support for and explanation regarding how it calculated its VIPER forecast. In its Direct Testimony supporting the Application, PG&E

[249] For example, Ex. ORA-80, PG&E Response to ORA-DR-056 Q4a, provides a narrative explanation for PG&E's assertion that VIPER costs will be higher, but no quantitative evidence supporting this assertion was provided. Ex. ORA-126, PG&E response to DR-ORA-141 Q2b states that "PG&E did not quantify the impact on unit costs based on its calculated difference in length [between PSEP and VIPER]." Ex. ORA-166, PG&E Response to DR-ORA-127 Q5 and Q1 similarly provides no quantitative evidence to support the degree to which VIPER costs will be higher, assuming PG&E's claim that VIPER projects will be more congested is valid.

explained: "The costs to replace vintage pipe with known interacting land movement are based on unit costs for varying diameters of pipe and historical costs for those various diameters of pipe during PSEP pipe replacement projects."[250] This explanation is supplemented with one page in PG&E's workpapers which contains the following "Summary Unit Cost Table" identified as Table 7.6-1 here.[251]

Table 7.6-1

PG&E-Proposed GT&S VIPER Unit Costs[252]

Years	Units	$/foot based on PSEP actuals & forecast 2012 & 2013 (x $1,000)
24'-30" Highly congested SF Peninsula/San Jose		
	$ per foot	$2,500
	$/mile	$13,200
16-12" Congested Sacramento		
	$ per foot	$1,100
	$/mile	$5,808
< 12" Congested		
	$ per foot	$1,000
	$/mile	$5,280

This PG&E-generated table shows that PG&E calculated its total VIPER Program forecast of $596.5 million for the rate case period using three unit costs based on the diameter of the pipes: $5.28 million, $5.8 million, and $13.2 million per mile for small, medium, and large diameter pipes respectively.[253] The balance of workpapers for this program (12 pages in total)[254] multiply these unit costs by estimated project lengths to derive <u>project</u> costs, which in turn are

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[250] Ex. PG&E-1 (Direct Testimony with Errata, Chapter 4A, Barnes), p. 4A-58.

[251] Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), p. WP 4A-722. In addition, page WP 4A-710 has a section titled "COST ASSUMPTIONS," but this only says "See Cost Calculator for details." There is no workpaper with the title or label "Cost Calculator." It appears that the reference is to page WP 4A-722.

[252] Source: Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), p. WP 4A-722.

[253] The project descriptions provided at Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), pp. WP 4A-712 to WP 4A-721 also list specific geographic locations such as Sacramento, and congestion level in the unit cost descriptions. However, as discussed in Section 7.6.4 below, projects in each size range are spread across PG&E's service territory, while PG&E has assumed that all projects in the 2015-2017 rate case time period will be in "highly congested" areas.

[254] See, e.g., Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), pp. WP 4A-712 to WP 4A-721.

summed to arrive at program costs.[255] Eighty one proposed GTS projects for 2015 through 2017 are listed on the first two pages of these workpapers, and the remaining ten pages list projects as "Post Rate Case."[256] PG&E's final step in developing its forecast was to apply escalation rates of 7%, 9.7%, and 12.6%, which increase the 2015 through 2017 requests to $193.824, $198.715, and $203.969 million respectively.[257]

In its Rebuttal Testimony, as discussed in more detail below, PG&E provided a new argument to support its forecast based on an analysis of a larger set of PSEP projects;[258] this analysis was later revised in response to an ORA data request.[259] Even later, PG&E revised its Rebuttal Testimony through errata to add six new projects to its large diameter pipe analysis. However, none of these new analyses resulted in revisions to PG&E's VIPER forecast. Evidently, they were intended to "validate" the reasonableness of PG&E's initial forecast by demonstrating that the addition of more projects does not change the outcome of PG&E's forecast. However, as ORA shows, these additional analyses merely perpetuate the cherry-picking PG&E engaged in for its original forecast.

PG&E's GT&S forecast also includes $12.75 million per year for its PMO,[260] and did not include an explicit contingency request.[261]

As a result of the paucity of PG&E's showing, ORA engaged in extensive discovery to understand and document the basis for PG&E's forecast. The very need for this discovery to understand basic elements of PG&E's VIPER Program forecast, because PG&E did not provide adequate evidence and justification, demonstrates the unreasonableness of PG&E's request.

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[255] Project costs for replacement of StanPac jointly owned pipe are multiplied by a "StanPac Factor " of .817143, presumably because this corresponds to PG&E's 6/7 ownership of StanPac. See Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), p. WP 4A-711, second column from right.

[256] Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), pp. WP 4A-712 to WP 4A-721.

[257] Ex. PG&E-5. See the first table on page WP 4A-711. ORA confirmed the annual value is correct by summing by year the projects costs in the larger table beginning on the same page.

[258] This revised analysis is not the same as PG&E's later revision in Errata, adding six additional projects to its analysis. See Section 7.6.4 below and Ex. PG&E-49 (Errata Vol. 3), pp. Errata 26 to Errata29. Neither revision impacted PG&E's VIPER forecast.

[259] Ex. ORA-124 (Excerpt from Revision 2 to Attachment 1 to DR-ORA-128 Q9).

[260] Ex. (Direct Testimony with Errata, Chapter 4A, Barnes), pp. 9-14 to 9-15. $12.75 million is the sum of 2015 expense and Capex requests.

[261] 19 RT 2030 (Barnes/PG&E).

Further, ORA's discovery and subsequent analysis revealed PG&E's forecast to be substantively unreasonable as well.

7.6.3 PG&E's Forecast Is Based On A Limited Sample Of Nine PSEP Projects Which PG&E Has Not Shown Are Representative Of VIPER Projects

PG&E claims that comparisons between the PSEP and VIPER forecasts are not valid because VIPER projects will be shorter and in more densely populated areas.[262] However, PG&E has not demonstrated that such differences in scope, to the extent they exist, will have a significant cost impact on VIPER Program costs. To the contrary, the following discussion shows that PG&E's use of only nine projects to inform its forecast – based on its assertion that they are representative of the VIPER Program work – results in a doubling of PSEP forecast costs and a more than 50% increase over PSEP actual costs that cannot be justified.[263]

The only quantitative support PG&E has provided for its requested unit costs is the following table, identified as Table 7.6-2 here, obtained through an ORA data request. This table provides limited information regarding the nine[264] PSEP projects PG&E relied upon to derive its unit costs.[265]

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[262] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), pp. 4A-66 to 4A-71.

[263] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 44. See footnote 131 regarding the range from 52% to 64%.

[264] As discussed in Section 7.6.4 below, PG&E added 6 projects to Table 7.6.2 late in the discovery process, increasing the number of projects to 15. PG&E's application and most of ORA's analysis was based on PG&E's original assertion that its forecast was based on the nine projects listed in Table 7.6.2, so this number is generally used in the brief.

[265] Ex. ORA-80 (PG&E Response to ORA-DR-56 Q3). The response also states "Please note that the data that was used to develop the cost estimates was as of 3/20/2013. Average costs per foot were rounded to the nearest hundred dollars, yielding the unit costs that are found in the workpapers on page WP 4A-722." PG&E thus rounds up the unit costs, and uses the higher unit costs in Table 4C-7 in its 2015 request.

Table 7.6-2

PG&E-Provided Support for VIPER Unit Costs[266]

PSEP Project #	Route	Diameter Range	Estimate at Completion (Includes Actuals & Forecasts)	Miles	Cost ($/Ft)
R-004	142S	< 12"	$ 5,414,078	1.04	$ 986
				Ave Cost/Ft	$ 986
R-006	111A	12" - 24"	$ 33,382,484	9.45	$ 669
R-037	172A	12" - 24"	$ 18,331,009	3.19	$ 1,088
R-061	196A	12" - 24"	$ 35,432,204	2.06	$ 3,258
R-066	119B	12" - 24"	$ 8,083,158	2.00	$ 765
				Ave Cost/Ft	$ 1,080
R-022	109	24"+	$ 46,132,492	3.26	$ 2,680
R-030	109	24"+	$ 20,851,345	1.61	$ 2,453
R-047	109	24"+	$ 4,885,313	0.47	$ 1,969
R-049	109	24"+	$ 6,714,142	0.67	$ 1,898
				Ave Cost/Ft	$ 2,476

*** Data as of 3/20/2013 ***

A few observations about this table. It shows that PG&E's VIPER forecast was based on nine projects. Unit costs for small diameter pipes were calculated based on only one project; unit costs for medium diameter pipes were calculated based on four projects; and unit costs for large diameter pipes were calculated based on four projects, but all of those projects were located on Line 109. While a column heading indicates that some of this project data is actual data from completed projects and some is forecasted, the table does not identify which costs are actual and which are forecast. In addition, ORA's data request asked "please provide all workpapers,

[266] Source: Ex. ORA-80 (PG&E Response to ORA-DR-56 Q3).

analyses, and calculations supporting PG&E's requested unit costs as provided on page WP 4A-722." PG&E's response included only this table, with no supporting attachments, and no justification as to why these projects are representative of VIPER projects.

In response to discovery, PG&E claimed that these projects were selected because they represent the type of short projects in congested locations it expects in the VIPER Program.[267] However, PG&E identified no specific length criteria and the evidence shows that PG&E omitted many PSEP projects it classified as "congested."

When ORA attempted to elicit information from PG&E's forecast sponsor regarding how PG&E determined which PSEP projects to include and which to exclude in its VIPER Program forecast (i.e. the specific criteria PG&E used to identify the nine projects), PG&E's witness claimed that projects were included to address the variability of the work that would need to be done and then asserted that PG&E "didn't exclude [any PSEP projects]."[268]

When questioned further, he explained that PG&E "didn't go to the level of detail of trying to break down individual PSEP projects to try to figure out whether they should or shouldn't be included. We picked the ones that had a congestion proportionality to them." He concluded: "That's what I can tell you, and that's how we did it."[269]

In other words, he didn't know how PG&E chose the nine projects and there were no real criteria. As evidenced in cross examination, PG&E's witness was unable to provide even one discernable selection criteria to support PG&E's choice of the projects it included in its forecast.

Given the lack of evidence to support PG&E's claims that it selected the nine projects based on congestion and project length, the only reasonable conclusion to draw is that PG&E's only criteria was to cherry-pick the projects that supported the highest forecast it thought it could request; there is no other rationale or record basis for how PG&E chose the projects that produced its forecast.

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[267] Ex. ORA-80 (PG&E Response to ORA-DR-056 Q4a). See also Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-70. (PG&E stated that GT&S projects are on average 2.6 times shorter than PSEP projects and that this length difference is a "significant factor that PG&E has accounted for in its higher unit cost compared to PSEP.").

[268] 19 RT 2062:24-25.

[269] 19 RT 2062-2063 and specifically 2062:24 – 2063:14 (Barnes/PG&E).

PG&E's rebuttal testimony added a new analysis which PG&E claimed provided validation of its proposed unit costs, using a larger group of projects. The following subsections discuss flaws in both of PG&E's analyses.

7.6.3.1 PG&E's Forecasted Unit Costs For Small Diameter Pipes Are Based On A Single Project

Table 7.6-2, reproduced above, shows that PG&E's unit cost for small pipes is based on a single project, R-004 on Line 142S. This unit cost excluded 12 other projects that were completed in 2012 and 2013.[270] Consistent with PG&E's own arguments regarding the advantage of programmatic forecasts informed by large amounts of data, basing a forecast on a single data point is fundamentally a bad practice, unless the exclusion of other projects can be justified. PG&E has provided no such justification in this case.

Exhibit ORA-131 shows that ORA's forecast including all 13 PSEP small diameter projects completed in 2012-2013, 11 of which are classified by PG&E as "congested," results in a unit cost of $3.90 million per mile, 25% less than PG&E's proposed $5.28 million per mile.[271] Further, using only the 11 small diameter PSEP projects classified as congested results in a unit cost of $4.05 million per mile, or 22% less than PG&E's proposed $5.2 million per mile.[272]

In its Rebuttal Testimony, PG&E challenged ORA's analysis using actual PSEP data from PG&E's Quarterly Compliance Reports. PG&E presented the results of its own analysis using additional PSEP data, which resulted in a forecasted a unit cost for small diameter pipes of $5.5 million per mile – thus presumably validating PG&E's original unit cost forecast of $5.28 million per mile.[273] PG&E's "alternative" forecast differs from ORA's by including two projects completed in 2014, and excluding two PSEP projects PG&E classified as "rural."[274]

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[270] Ex. ORA-131, p. 1.

[271] Ex. ORA-131, p. 2, cell J21. 1- ($3.9/$5.2) = 25%.

[272] Ex. ORA-131, p. 2, cell J22. 1- ($4.05/$5.2) = 22%. Projects R-038 and R-074 on lines 6 and 11 respectively are classified as rural and removed from this calculation.

[273] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p.4A-74, Table 4A-13.

[274] Ex. ORA-131, p.2 also shows that for the 11 projects common to both PG&E and ORA analysis, PG&E's unit cost is about 10% higher, $4.51 vs. $4.05 respectively. The difference is driven by two projects, R-071 in line 10 and R-148 in line 19. ORA did not investigate why the costs for these two projects was significantly lower in the PSEP Reports than in the data PG&E used.

As discussed in more detail in Section 7.6.6 below, ORA recognizes that both the PSEP and VIPER Programs focus on highly populated areas. However, both will likely include at least some projects or sections of projects in less populated areas, consistent with ORA's forecast, rather than being located only in congested areas, as assumed in PG&E's forecast.

7.6.3.2 PG&E's Forecasted Unit Costs For Medium Diameter Pipes Are Based On Four Projects, Each One With Data Or Other Anomalies

Table 7.6-2, reproduced above, shows that PG&E's unit cost for medium pipes is based on four projects. PSEP Quarterly Report Data reflects that one of those projects was completed in 2013; two were completed in 2014 and the last had no completion date identified.[275] Exhibit ORA-131 shows that PG&E used forecast data on at least three of these projects, while it excluded ten projects that were completed in the 2012-2013 timeframe with actual cost data available.[276]

Consistent with PG&E's own arguments regarding the advantage of programmatic forecasts informed by large amounts of data over a period of time, basing a forecast on a small amount of data – especially when much of that data is forecast rather than actual – is fundamentally a bad practice, unless the exclusion of other projects can be justified. As described above, PG&E has provided no such justification in this case.

Exhibit ORA-131 shows that ORA's forecast using PSEP Quarterly Report data for the ten completed projects, eight of which are classified by PG&E as "congested," results in a unit cost of $3.94 million per mile, 32% less than PG&E's forecast of $5.8 million per mile.[277] Further, using only the 8 PSEP projects classified as "congested" results in an even lower unit cost of $3.68 million per mile, 37% lower than PG&E's proposal.[278]

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[275] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 39, Table 4C-9.

[276] Ex. ORA-131, p. 1. Project R-006, line 27 of the exhibit, has a tie-in date of 2/28/2013 and PG&E's unit costs used data as of 3/20/2013, as shown in the note to Table 4C-8 above. This should have allowed PG&E to use actual data for this project, but the cost used by PG&E is $33.382 million, while the actual cost is closer to $35 million.

[277] Ex. ORA-131, p. 2, cell J44. 1- ($3.94/$5.8) = 32%.

[278] Ex. ORA-131, p. 2, cell J45. 1-($3.68/$5.8) equals 36.6%. Projects R-073 and R-133 on lines 36 and 40 respectively are classified as rural and removed from this calculation.

In response to ORA's showing, PG&E's Rebuttal Testimony included a forecast based on 14 medium diameter PSEP projects (later revised to 11 projects) showing a forecasted unit cost of $5.55 million per mile – thus presumably validating PG&E's original unit cost forecast of $5.8 million per mile.[279] As with the alternative small pipes analysis, PG&E's unit cost is higher than ORA's because PG&E included three higher priced projects completed in 2014. Notably, ORA's Direct Testimony had highlighted the data quality and other problems it observed regarding all four of the projects PG&E originally used to forecast its medium pipe unit cost.[280] Evidently, PG&E agreed with ORA's observations because its Rebuttal Testimony analysis excluded two of those four projects.[281]

7.6.3.3 PG&E's Forecasted Unit Costs For Large Diameter Pipes Are Based On Four Projects From The Same Line Located In The High Cost San Francisco Peninsula Region

Table 7.6-2 reproduced above, shows that PG&E's unit cost of $13.2 million per mile for large pipes is based on four projects, all located on Line 109 in the high cost Peninsula region.[282] This unit cost excluded 15 other projects that were completed in 2012-2013 throughout PG&E's service territory.[283]

Exhibit ORA-131 shows that ORA's forecast including all 19 projects completed in 2012 and 2013, 15 of which are classified as "congested" by PG&E, results in a unit cost of $7.19

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[279] Ex. ORA-131, p. 2, cell E44 and Ex. ORA-124, Revision 2 to attachment 1 to PG&E's response to ORA 128, Q9.

[280] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p.40.

[281] Ex. ORA-131, p. 1. Projects R-006 and R-061 on lines 27 and 33 respectively are included in the four projects supporting PG&E Direct and Errata testimony, as shown in columns B and C, but not in the 14 or 11 projects supporting PG&E Rebuttal testimony, as shown in columns D and E.

[282] In errata filings, PG&E revised this analysis to include six more projects on Line 109, but this was only in response to ORA inquires after PG&E's analysis was completed, and it did not result in a change in the proposed unit cost of $13.2 million per mile. PG&E's last-minute revision during hearings professed to explain why it added these projects: because it "reviewed its data in more detail and identified six additional projects that were also representative of the projects forecasted for the rate case period, and inadvertently failed to provide those projects to ORA in response to ORA56, Q3." See Ex. PG&E-158, p.4A-71, FN 102.

[283] Ex. ORA-131, p. 1.

million per mile, 46% less than PG&E's proposed $13.2 million per mile.[284] Even if the forecast was only based on projects PG&E classified as congested, the unit cost for the remaining 15 projects is $8.39 million per mile, or 36% less than PG&E's proposed $13.2 million per mile. [285]

Consistent with PG&E's own arguments regarding the advantage of programmatic forecasts informed by large amounts of actual cost data, basing a forecast on a small amount of data is fundamentally a bad practice, unless the exclusion of other projects can be justified. As described above, PG&E has provided no such justification in this case.

In Rebuttal Testimony, PG&E challenged ORA's forecast, and presented results of its own analysis adding six more projects, which resulted in a unit cost for large diameter pipes of $12.1 million per mile, an 8.3% or $1.1 million per mile reduction from PG&E's proposed unit cost of $13.2.[286] PG&E subsequently revised its analysis and increased the unit cost to $12.3 million per mile, presumably validating PG&E's forecast of $13.2 million per mile.[287] As discussed in the next section, PG&E revised the support for its original analysis by coincidently adding six projects, but not the same six projects.[288]

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[284] Ex. ORA-131, p. 2, cell J68. 1- ($7.19/$13.2) = 45.5%.

[285] The $8.20 million per mile value was obtained by removing projects R-006, R-007, R-049, and R-051 from the calculations supporting Ex.ORA-131, p.2. 1- ($8.39/$13.2) = 36.3%.

[286] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p.4A-74, Table 4A-13. $12.1 is from the original rebuttal testimony. This value was revised in a 10/3/14 errata filing (Ex. PG&E-46) to $12.3. While only the value was changed, the rebuttal text at Ex. PG&E-46 (Errata Vol. 1), page ERRATA-61 states: "Correction to rebuttal testimony page 4A-74, Table 4A-13, line 3, to correct a calculated unit costs to include a project that was inadvertently excluded from the analysis." No other information was provided in the errata to explain which project was excluded. Ex. ORA-124, PG&E responses to DR-ORA-128 Q9 indicates that R-026 was included in the original attachment 1, but the bulk of the costs were only added in the second revision to this attachment, so ORA believes this is the referenced project.

[287] Ex. ORA-124, revision 2 to attachment 1 to PG&E's response to DR-ORA 128 Q9.

[288] As summarized in Ex. ORA-131, p. 1, project R-021, which had a cost of $9.5 million per mile, was included in PG&E's rebuttal analysis Table 4A-13, but not in PG&E's Errata analysis, as shown in line 54. Conversely, project R-067, which had a cost of $16.7 million per mile, was <u>not</u> included in PG&E's rebuttal analysis Table 4A-13, but was included in PG&E's Errata analysis, as shown in line 66. This exchange of a more expensive project for a less expensive one resulted in the $1.1 million difference between PG&E's two analyses.

Both of PG&E's analyses were based on ten projects, all performed on Line 109, including one PG&E classified as "rural."[289] PG&E's analysis differs from ORA's in that while ORA used all 19 large diameter pipe projects completed in 2012 and 2013, PG&E excluded the nine projects that were not on L-109, six of which PG&E classified as "congested."[290] At a minimum, PG&E's proposed unit cost of $13.2 million per mile should be reduced to $12.3 million per mile based on PG&E's own analysis. However as discussed below, both numbers are based on the incorrect assumption that all VIPER projects involving large pipelines will be on L-109, or in the high cost San Francisco Peninsula region, and will incur the higher costs that PG&E previously claimed were unique to this region.[291]

As a practical matter, less than half of the 27 currently proposed large diameter VIPER projects will be located on the San Francisco Peninsula region, so it is unreasonable to apply the unit costs from this high cost region to all 27 proposed projects to be performed across PG&E's service territory.[292] Second, since PG&E has requested flexibility to revise its proposed project list and location relative to the San Francisco Peninsula region is not a criteria for inclusion in VIPER, there could be more projects outside of the San Francisco Peninsula region as the program evolves.[293] Finally, PG&E showed in PSEP that it believes replacement projects on the San Francisco Peninsula region are the most expensive, by including an adder for $200 per foot to six projects on L-109 and L-101.[294] PG&E provided no evidence in that case to justify including this adder on those six projects, and it has provided no evidence to support implicitly applying this adder to all 27 large diameter VIPER projects.

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[289] Ex. ORA-131, p. 1, R-049, cell J64.

[290] Ex. ORA-131, p. 1, R-049, lines 48-53, 56, and 65.

[291] Ex. ORA-86 (Supporting Attachments, Part 7 – PSEP DRA-03, Direct Testimony, Roberts), pp.53-54.

[292] Ex. ORA-92 (ORA Workpaper "WP-ORA-4C-13.xls," tab "ORA-088 Q3-ORA"), Column I filtered for large pipes, Column R filtered for Santa Clara, San Mateo, and San Francisco Counties. Three projects in San Jose are not technically on the San Francisco Peninsula.

[293] Ex. PG&E-1 (Direct Testimony with Errata, Chapter 4A, Barnes), p. 4A-58, Figure 4A-11.

[294] Ex. ORA-86 (Supporting Attachments, Part 7 – PSEP DRA-03, Direct Testimony, Roberts), pp.53-54.

7.6.4 PG&E Revisions To Its Testimony Through Revised Data Responses And Errata Have No Impact On PG&E's Forecast And Continue To Propagate Errors

In December 2014, PG&E unilaterally revised its response to a May 2014 ORA data request that asked PG&E to provide support for its proposed VIPER unit costs.[295] In this data response revision, PG&E increased the number of projects it claimed supported its unit costs from nine to 15 by adding six projects on L-109 to support the $13.2 million unit cost forecast for large pipes. As discussed in the previous section, these are not the same six projects as were added in PG&E's rebuttal Table 4A-13.[296] The revised response did not explain the reasons for this change, but the data indicates the original four projects PG&E had been relying upon did not support the proposed $13.2 million per mile unit cost.[297]

In January 2015, PG&E issued an errata to its Rebuttal Testimony documenting only the overall change from nine to 15 projects;[298] a second errata issued during hearings explained that the six projects were added following ORA's probing into PG&E's calculations.[299]

The need for PG&E to change its limited support for its unit costs so late in the proceeding is additional evidence of the random and unreasonable nature of PG&E's analysis. ORA did not object to PG&E's modification of its testimony through errata in this instance, even though it was an improper addition of a new argument to its testimony,[300] because it further

[295] Ex. ORA-125 (Revision 1 to PG&E's response to DR-ORA-56 Q3.)

[296] As summarized in Ex. ORA-131, p. 1, project R-021, which had a cost of $9.5 million per mile, was included in PG&E's rebuttal analysis Table 4A-13, but not in PG&E's Errata analysis, as shown in line 54. Conversely, project R-067, which had a cost of $16.7 million per mile, was not included in PG&E's rebuttal analysis Table 4A-13, but was included in PG&E's Errata analysis, as shown in line 66. This exchange of a more expensive project for a less expensive one resulted in the $1.1 million difference between PG&E's two analyses.

[297] Ex. ORA-125 (Revision 1 to PG&E's response to DR-ORA-56, Q3), p. 2. The bottom-right cell in the revised table on page 2 shows an original "Ave Cost/ft" of $2,476 per foot, or $13.07 million per mile, which was revised to $2,514 per foot, or $13.27 million per mile.

[298] Ex. PG&E-49 (Errata Vol. 3), pp. ERRATA 23 to ERRATA 27.

[299] Ex. PG&E-158 (February 10, 2015 Errata, Chapter 4A, Barnes), p. 4A-71, footnote 102 PG&E's last-minute revision during hearings professed to explain why it added these projects: because it "reviewed its data in more detail and identified six additional projects that were also representative of the projects forecasted for the rate case period, and inadvertently failed to provide those projects to ORA in response to ORA56, Q3."

[300] 26 RT 3484:28 – 3486:5 (ALJ ruling granting motion to strike errata on the basis that errata cannot be

demonstrates the unreasonableness of PG&E's large diameter forecast. Now PG&E relies upon six more projects, all located on L-109, to support that forecast. As discussed above, PG&E's complete reliance on projects from this line and in the highest cost area, given the breadth of other projects available and the fact that not even half of the VIPER projects are likely to be located in the San Francisco Peninsula region, is inappropriate.

7.6.5 The Evidence Demonstrates That PG&E Cherry-Picked The Nine Projects It Used For Its VIPER Forecast To Produce The Highest Forecast It Felt It Could Justify; It Is Unreasonable On Its Face

PG&E is requesting a 2015 VIPER Program budget of $193.8 million based on a unit cost forecast derived from costs (some forecast and some actual) from a small subset of PSEP pipe replacement projects. PG&E had two years of actual cost data available to it, representing 42 completed projects. Instead, PG&E chose to cherry-pick nine projects, only four of which. Four of its projects – more than a third of those relied upon – were not tied-in or completed before PG&E prepared its Application.[301] When asked what criteria it applied to choose those projects, PG&E's forecast sponsor was unable to provide any specific criteria PG&E used other than vague references to "congestion."[302] However, PG&E's forecast excludes 29 PSEP projects completed in 2012 and 2013 which PG&E itself classified as "congested."

By its own testimony regarding the value of programmatic forecasts,[303] PG&E fails the test of reasonableness.

PG&E's efforts to resuscitate its poor showing in its Rebuttal Testimony and then through errata are similarly unpersuasive. As described above, PG&E attempted to counter ORA's analysis in Rebuttal Testimony by expanding the scope of its analysis from nine to 35 projects to show that the use of more data produced the same results. However, as also shown above, PG&E continued to selectively include and exclude projects – including projects from 2014 to obtain averages that supported its proposed unit costs. Its further modification of its

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used to introduce new arguments).

[301] Ex. ORA-131, p.1. Only five projects have a tie-in date before PG&E's cut off data of March 20, 2013: R-004, R-006, R-030, R-047, and R-049.

[302] 19 RT 2062:24-25 and 2062-2063 generally.

[303] See Notes 47 and 81. The figure of 29 is relative to PG&E's original use of nine projects.

testimony through an errata was similarly unpersuasive given PG&E's inappropriate reliance on only projects located on L-109 for its large diameter forecast.

The ultimate nail in the proverbial casket to all of these efforts is that there is nothing on the record substantiating why any of PG&E's cherry-picked projects – whether 9, 15, or 35 – provide a reasonable basis for forecasting costs for the VIPER Program. PG&E has failed to provide any evidence that the projects it has used to calculate its forecast are representative of VIPER projects, therefore justifying its selective use of project data.

ORA's forecast of $110 million for 2015 is based on unit cost forecasts using two years of actual cost PSEP data from completed projects. Where data is excluded, such as for those projects completed early in 2014, ORA followed and documented its clear and rational criteria.[304] As such, ORA's forecast is reasonable and should be adopted.

7.6.5.1 PG&E Claims Costs Will Be Higher Than PSEP Because VIPER "Is Targeted On Very Short Segments Of Pipe That Are In Congested Locations,"[305] But Provides No Support

PG&E's VIPER Program forecast of $596.5 million for the rate case period is based on 81 proposed pipe replacement projects for 2015 through 2017.[306] ORA analysis shows that PG&E's unit cost forecast supporting this request is more than double the PSEP forecasts approved in D.12-12-030, and 52% to 64% more than its PSEP actual costs in its VIPER Program forecast.[307]

PG&E's primary justification for a VIPER forecast so much higher than the PSEP forecast or PSEP actual costs is that VIPER "is targeted on very short segments of pipe that are in congested locations."[308] However, as discussed above, PG&E provided limited information to support these two assertions. Nevertheless, ORA provides evidence to show that both of

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[304] See Section 7.6.12 below. See Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p.23, footnote 64 regarding 2014 projects.

[305] Ex. ORA-80 (PG&E Response to ORA-DR-056 Q4a).

[306] The 81 proposed projects have significantly different diameters, lengths, and population densities based on PG&E's own "total occupancy count" (%TOC) calculations. Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), pp. WP 4A-711 to WP 4A-712.

[307] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 44 and Table 4C-12.

[308] Ex. ORA-80 (PG&E Response to ORA-DR-056 Q4a), emphasis added.

PG&E's justifications for its extremely high VIPER forecast are unlikely to be true, and that PG&E's forecast is therefore unreasonable.

In sum, ORA's analysis shows that even if the average length of a VIPER replacement project is significantly shorter than the average length of a PSEP project, this does not justify a VIPER forecast more than 50% higher than PSEP actual costs. ORA also shows that PG&E's forecast assumption that all VIPER projects will be located in congested areas is without merit and will not result in higher actual costs for the VIPER Program.

7.6.5.2 The Difference In VIPER And PSEP Project Lengths Is Not As Great As PG&E Claims And, In Any Event, Do Not Justify A Forecast More Than 50% Higher Than Actual PSEP Costs

In its Direct Testimony addressing the difference between its PSEP and VIPER forecasts, PG&E provided no support for its claim that VIPER projects are "very short" compared to PSEP projects.[309] PG&E elaborated minimally in its Rebuttal Testimony, explaining that "each project in PSEP is, on average, 2.6 times as long as a segment identified for replacement in the GT&S rate case"[310] but provided little data in support. It explained that this length difference "is a significant factor that PG&E has accounted for in its higher unit cost compared to PSEP."[311] Again, PG&E provided no quantification of "how much" of its additional costs were attributed to the difference in project lengths. PG&E explained the cost increase was because VIPER "will have within its unit costs more cost pressure from fixed costs such as mobilizations and demobilization of personnel, equipment, and materials for many short length projects of varying size and design need."[312]

In response to discovery, PG&E further clarified that the higher costs were not due to higher fixed costs *per se*, but rather an increase in the frequency of occurrence of fixed costs.[313]

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[309] Ex. ORA-80 (PG&E Response to ORA-DR-056 Q4a).

[310] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-70.

[311] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-70.

[312] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-71:1-5.

[313] Ex. ORA-126 (PG&E Responses to ORA-DR-127 Q4 and Q8). At 19 RT 2016, TURN asked "What do you mean by fixed costs?" and PG&E's witness answered "So generally speaking, that [Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-71] was giving a list of examples of those fixed costs. And so think of it in terms of when you're having to mobilize for a project, you have to have

In Rebuttal Testimony, PG&E calculates that the average length for a PSEP project is 9,931 feet, which PG&E states is 2.6 times longer than the average VIPER project of 3,837 feet.[314] PG&E explains in discovery that its target for VIPER is to replace approximately 60 miles of pipeline in 2015-2017, which will require more VIPER projects of shorter lengths, as compared to fewer PSEP projects of longer lengths.[315]

PG&E's assertion that VIPER will require more projects, and will incur more fixed costs is correct: PG&E will need to complete 83 projects using the VIPER average project length,[316] but would only need 32 projects using the PSEP average length.[317] Thus, the shorter average lengths in VIPER increase the number of projects required by 51, from 32 to 83, and increase the frequency in which the fixed costs are incurred, thus increasing the total fixed costs for the VIPER program.[318]

As described below, ORA challenges not the concept that shorter average project lengths increase program fixed costs, but rather whether the cost increase is significant, let alone responsible for a doubling of the PSEP forecasts and actual pipeline replacement cost increases of 52% to 64% from PSEP to VIPER. Specifically, the increase in the frequency that fixed costs are incurred during 2015-2017 is only significant relative to PG&E's overall request for $596.5 million if the fixed costs are large compared to the total variable costs for the program.[319]

PG&E claims that it "does not have the ability" to parse PSEP pipe replacement costs into fixed and variable components, and it hasn't performed this analysis.[320] In hearings its

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equipment and personnel and materials mobilized to the site. And once you're done with the project, you have to do clean up and demobilization from the site. And those are -- they're kind of like one-time costs. They're not per mile costs."

[314] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-70, Table 4A-12.

[315] Ex. ORA-126 (PG&E Response to ORA-DR-127 Q8.

[316] For VIPER, 60 miles*(5280 ft/mile)/(3,837 ft/project)= 82.6 projects. Note that PG&E workpapers actually provide for the completion of 58.86 miles with **81 projects**. See ORA-34 (Direct Testimony, Corrected Version, Roberts), p.35, Table 4C-6.

[317] Using PSEP average length, 60 miles*(5280 ft/mile)/(9,931 ft/project)= 31.88 projects.

[318] Ex. ORA-126 (PG&E Response to ORA-DR-127 Q8).

[319] Ex. PG&E-1 (Direct Testimony with Errata, Chapter 4A, Barnes), p. 4A-55, Table 4A-16, sum of 2015-2017 values.

[320] Ex. ORA-132 (PG&E responses to DR-ORA-90, Q4, Q5, and Q6).

witness sponsoring the forecasts was unable to provide any additional information on this topic, other than to confirm that PG&E's accounting system does not provide an ability to break down PSEP project costs by variable and fixed costs.[321]

Given this lack of PG&E data, ORA looked for other ways to understand the relationship between fixed and variable pipe replacement costs.

As an initial matter, ORA examined PG&E's claim that PSEP projects are 2.6 times longer than the proposed VIPER projects and found that this was not accurate. First, ORA's analysis shows that PG&E did not do an apples to apples comparison because it compared PSEP actual length data to VIPER forecast length data. A more relevant comparison between PSEP forecast lengths and VIPER forecast lengths shows that PSEP forecast lengths were only 1.5 times longer than VIPER forecast lengths.[322] This comparison is relevant because it also shows that PG&E significantly under forecasted the length of PSEP projects,[323] and there is no reason to assume the same will not occur for the VIPER Program, thus challenging PG&E's claim that VIPER projects will be short.

More significantly – using PG&E testimony and data regarding fixed and variable costs supporting its PSEP pipe replacement forecast – ORA found that differences between the PSEP and VIPER average project lengths – whether 3,837 feet for VIPER or 5,802 for PSEP forecasts or 7,534 for PSEP actuals – do not result in significant cost increases to the total VIPER Program for two reasons:

1. Assuming $145,000 per project for fixed costs based on a generous reading of PG&E data supporting its PSEP forecast,[324] the

[321] 18 RT 1957-1958 and 19 RT 2022-2024 (Barnes/PG&E).

[322] 1.5= 5,802 ft for PSEP divided by 3,837 ft for GTS. The 5,802 value is from PG&E's PSEP testimony: 185.7 miles*(5280 ft/mile)/169 projects= 5,802 ft. See Ex. ORA-85 (PG&E PSEP Prepared Testimony in R.11-02-019, Hogenson),p. 3-63, Table 3-3.

[323] PG&E forecasted an average of 5,802 feet for all PSEP replacement projects, as provided in the previous footnote. ; it provided the average length of completed PSEP projects as 9,931 feet in Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-70, Table 4A-12.

[324] ORA assumes project fixed costs of $145,000 based on PG&E PSEP estimates of a maximum mobilization/demobilization (Mob/Demob) Charge of $95,000 and Move Around Charge of $50,000. This estimate is conservative since Move Around Charges were applied to only 18 of 168, or11% of the proposed PSEP projects. See Ex. ORA-92, ORA Workpaper "WP-ORA-4C-7, PSEP REPL Forecast.xls," tab "Project Data," Column Z. Further, the Mob/Demob Charge varied from $45,000 to $95,000 depending on the pipeline diameter. The Move Around Charge varied from $25,000 to $50,000

additional fixed costs associated with PG&E's 51 replacement projects (which is also a significant overestimate)[325] would add only $7.4 million to the total 2015-2017 VIPER program cost of $596.5 million, or an increase of 1.2%.[326]

2. PG&E's PSEP pipe replacement forecast cost data, which D.12-12-030 determined was "at the high end of the range of reasonableness"[327] shows that for PSEP pipe replacement projects longer than 500 feet, fixed costs are equalized by variable costs, and the variable costs per foot become the driving factor in total project costs.

This second point requires elaboration. PG&E stated that VIPER unit costs would be higher because "costs that are fixed for each of these projects would be spread over a smaller number of feet, resulting in a higher unit cost per foot."[328] The following excerpt from Ex. ORA-127 illustrates this point:

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depending on the pipeline diameter. See Ex. ORA-85 (PG&E PSEP Prepared Testimony in R.11-02-019, Hogenson),p.3E-15.

[325] For example, using the average PSEP forecast length of 5,820 PG&E provided in the PSEP proceeding, ORA calculates that shorter VIPER projects would result in only 28 additional projects, rather than the 51 calculated by PG&E relying upon a PSEP average footage of 9,931. 60 miles*(5280 ft/mile)/(5,802 ft/project)= 54.6 projects. 83 project minus 55 projects is 28. 28 x $145,000 = $4.06 million.

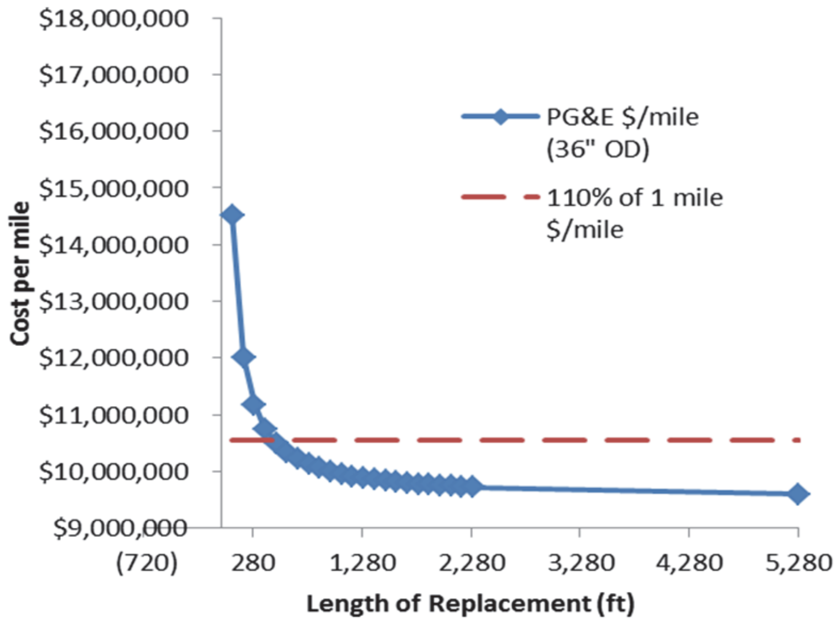
[326] $7.4/$596.5 = 0.0124 or 1.24%. Using only the Mod/Demob cost of $95,000 that applied to all PSEP projects, and the lower number of projects discussed in the previous footnote, 28, the increase in fixed costs is $2.66 million, or a .5% increase ($2.66/$596.5 = 1.00446).

[327] D.12-12-030, COL 33, p. 125 and also generally p. 70.

[328] Ex. ORA-126 (PG&E responses to DR-ORA-90 Q4, Q5, and Q6.)

Figure 7.6 -

Pipe Replacement Unit Cost vs. Project Length



However, this figure also illustrates a corollary point: that VIPER unit costs decline rapidly as length increases and then stabilize.[329]

While PG&E has been unable to provide a breakdown of fixed and variable costs for completed PSEP projects,[330] it did provide this breakdown in the PSEP proceeding for the PSEP forecast pipe replacement costs. The PSEP forecast data used for this exhibit show that pipe replacement unit costs stabilize to within 10% of the maximum cost per foot for projects 500 feet or longer, the point at which fixed costs are eclipsed by variable costs in the calculation of total costs.[331]

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[329] Ex. ORA-127.

[330] Ex. ORA-126 (PG&E responses to DR-ORA-90 Q4, Q5, and Q6.)

[331] Ex. ORA-127, cells G7 and G8. This exhibit used PG&E's PSEP forecast data for large pipes in highly congested areas. No Move Around Charges were included because PG&E did not include one in 89% (151 of the 169) of proposed PSEP projects. Including the maximum Move Around Charge raises the cross over point from <500 ft. to <700 ft. The one mile unit cost of $9.593 million per mile (cell D27) was used to establish the "110%" line in this exhibit as a proxy for the maximum unit cost, which is actually the variable unit cost of $1,799 per foot or $9.499 million/mile.

This means that for pipeline replacement projects, project length has minimal impact on project unit costs, except for projects shorter than 500 feet, or approximately 0.1 mile. Therefore, VIPER will only have a unit cost that is significantly higher than PSEP if it has significantly more projects than PSEP that are very short, or less than 0.1 miles long. PG&E's workpapers show that only 8 projects in VIPER are shorter than 0.1 miles long, less than 10% of the total 81 projects planned for 2015-2017.[332] In comparison, 50% of the planned PSEP projects (84 projects) were shorter than 0.1 mile long, as indicated by the median value of 509 feet (0.096 miles) provided in ORA's testimony.[333] Therefore, a much smaller proportion of VIPER projects during the rate case period are short enough to have significantly higher unit costs compared to PSEP, and PG&E's claim that VIPER will be more expensive due to shorter projects has no basis.

A final perspective on project length and cost is that very short projects have a small impact on the overall portfolio unit cost because they are short, absolutely, compared to the aggregate portfolio cost and length.[334] For example, the 84 planned PSEP projects shorter than 500 feet have a total length of 10,651 feet, which is only 1.09% of the 185.7 mile total length of all 169 forecasted projects.[335] For VIPER, the 8 projects shorter than 500 feet have a total length of .51 miles, which is only 0.87% of the total length for all 81 projects.[336] Consequently, the impact of these shorter projects on the unit cost of the complete portfolio of projects will be small.

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[332] Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), pp. WP 4A-711 and WP 4A-712.

[333] Ex. ORA-92, Workpaper "WP-ORA-4C-7, PSEP REPL Forecast.xls," tab "Histogram of L," cell B171. ORA's initial analysis provided in direct testimony used the median statistic rather than the average statistic because it understood that there was a cross-over point in terms of length beyond which project length has a minimal impact on cost.

[334] For example, assume the program only has two projects, A and B. A is very short and expensive in terms of unit cost (length= 100 ft, cost = $275,000, $/mile = $14.5 million) and B is an average PSEP project (length=5,802 ft, cost= 10.5 million, $/mile =$9.56 million). The program average of these two projects is $9.64 million per mile ($10.775 million/5,902 ft*5208 ft/mile).

[335] Ex. ORA- 92, ORA Workpaper "WP-ORA-4C-7, PSEP REPL Forecast.xls", tab "Histogram of L", column B sorted and summed for 84 shortest projects.

[336] 0.87 % = .51 miles/58.86 miles. See Ex. ORA-92, ORA WP "WP-ORA-4C-5, VIPER Statistics.xls," tab "Histogram of L," Column J. Values obtained by sorting by project length and summing the short vs. long lengths.

7.6.6 PG&E's Claims That Costs Will Be High Because VIPER Projects Will Be Located In Heavily Populated Areas, Is Not Demonstrated And Unreasonably Inflates The VIPER Forecast

The second part of PG&E's justification for a doubling of unit costs compared to the PSEP forecast, and a more than 50% increase in PSEP actual costs, is that PG&E asserts that VIPER projects will be in heavily populated areas initially because of the % TOC method it uses to prioritize work.[337] PG&E therefore only provided and proposed unit costs for congested areas.[338]

However, PG&E's justification for relying only on "congested" areas in its forecast fails for each of the following reasons, as described in more detail below:

1. PG&E's choice to prioritize projects based on AOC is not fundamental to the stated goals of the program;
2. PG&E fails to recognize that PSEP work focused on highly populated HCAs as a fundamental requirement of the program, thus the vast majority of PSEP projects are located in "congested" areas;
3. In PSEP, PG&E increased the scope of pipe replacement to include non-HCA areas where it improved the efficiency of the program. PG&E has provided no evidence that a similar shift to less populated areas should not be expected for VIPER;
4. PG&E provides no analysis or quantitative support to show how the project locations anticipated for VIPER will lead to increased costs compared to PSEP;
5. PG&E's forecast for large pipes assumes all projects will be in the "super congested" SF Peninsula – thus assuming even higher costs;
6. Within the rate case period, the level of congestion decreases based on PG&E's AOC prioritization process, which should result in VIPER projects located in less congested areas, thus reducing annual program costs; and

337 Total Occupancy Count (TOC) is a measure of how many people are within the potential impact radius (PIR) of a pipeline. PG&E determines the OC for each section of pipe it will replace, which establishes what percentage of the TOC will be impacted by replacing the particular section of pipe. This is the % TOC. See Ex. PG&E-1 (Direct Testimony with Errata, Chapter 4A, Barnes), p. 4A-54.

338 Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), p. WP 4A-722.

7. PG&E's definition of "congested" relative to VIPER is poorly defined and has changed over the course of this proceeding.

First, PG&E's choice to prioritize projects based on average occupancy count (AOC) is not fundamental to the stated goals of the program. PG&E's Vintage Pipeline Replacement program "targets the threat posed by the presence of [fabrication and] construction defects as they interact with outside forces such as land movement."[339] VIPER's primary selection criteria are therefore: (1) pipe characteristics; and (2) locations with certain geologic conditions, neither of which is dependent on the local population density. It is only PG&E's new and untested AOC prioritization process that has any impact on whether a VIPER project is in a rural area or one that is highly populated. Stated another way, VIPER must include projects based on what is beneath the surface (pipe characteristics and land movement), but PG&E chose to prioritize projects based on what is above the ground (people).

ORA did not challenge PG&E's proposed AOC prioritization plan, except to observe that prioritized PSEP replacement projects should be completed before VIPER begins.[340] However, information provided in discovery and hearings raises serious doubts about this methodology. If the Commission rejects PG&E's AOC prioritization methodology in favor of one that prioritizes based on high consequence areas (HCAs) consistent with federal and state regulations, PG&E's claim that VIPER projects are in more congested locations will have no merit because VIPER will have the same location criteria as PSEP based on HCAs. This new information did not lead ORA to lower its forecast, but it does add support to the fact that ORA's use of actual costs for all PSEP projects in 2012-2013 to forecast unit costs for the VIPER Program is reasonable.

Second, PG&E fails to recognize that the PSEP work was required to focus on highly populated HCAs. The decision leading to PG&E's PSEP application ordered that "the Implementation Plan [PSEP] should start with pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas."[341] PG&E's PSEP application

[339] Ex. PG&E-1 (Direct Testimony with Errata, Chapter 4A, Barnes), p. 4A-52.

[340] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 34-35.

[341] D.11-06-017, p. 31, OP 4.

prioritized pipelines in "urban areas" for inclusion in PSEP Phase 1, which covered projects in 2011 to 2014.[342] It further characterized that PSEP Phase 1 would focus "on areas of potentially significant impact on people," [343] and pipe replacement in "densely populated areas or HCAs."[344] Therefore, in PSEP PG&E used the federal Class Location and HCA definitions to prioritize projects where the consequences of a pipe failure in terms of human harm were greatest.[345] It is not evident that VIPER projects will be located in more densely populated areas than the PSEP projects, or if any increase in population density will increase the unit costs beyond those for HCAs in PSEP, which were found to be at the high end of the range of reasonableness.

PG&E not only ignores the fact that PSEP was focused on HCAs, but it totally abandons the HCA prioritization concept in GT&S. For this proceeding, PG&E claims that its prioritization method is "really all about people," and proposes a new unproven method to determine areas of high population density, AOC.[346] In hearings, PG&E's witness Barnes didn't seem to understand that federal law established the class location system and HCA designations to categorize human impacts from pipeline failures,[347] when the federal codes defining HCAs and class locations clearly use the number of buildings as a proxy for human impacts.[348] PG&E's support for the use of AOC to prioritize VIPER Projects was not strong enough to convince the Commission's Safety and Enforcement Division (SED) to change its initial finding

[342] Ex. ORA-85 (PG&E PSEP Prepared Testimony in R.11-02-019, Hogenson), p.3-4, Figure 3-1.

[343] Ex. ORA-85 (PG&E PSEP Prepared Testimony in R.11-02-019, Hogenson), Attachment 3B, p. 3B-13, emphasis added.

[344] Ex. ORA-85 (PG&E PSEP Prepared Testimony in R.11-02-019, Hogenson),p. 3-16.

[345] Class locations are defined in 49 CFR 192.5. HCA is defined in 49 CFR 192.903.

[346] 18 RT 1804, (Barnes/PG&E).

[347] 18 RT 1932, (Barnes/PG&E): "I take exception to your defining it as human impact to pipeline failure. That's not actually how the code has used that information. What the code has done is used that to define the limits upon which you do certain activities such as Subpart O integrity management activities." "

[348] Class location definitions at 49 CFR 192.5 (b) (3)(A) indicate a focus on human impacts: "Class 3 location is: (i) Any class location unit that has 46 or more buildings intended for human occupancy." The definition of HCA is also focused on buildings occupied by humans: 49 CFR 192.903(1)(iii) "Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy."

that PG&E's AOC/TOC concept was "deficient" because " by itself is an insufficient means of prioritizing absent a complementary risk evaluation."[349] [350]

Third, In PSEP, PG&E requested, and was granted the ability to include pipe segments outside of HCA areas based on PG&E's engineering judgment. This request was based on cost efficiencies, among other things. ORA supported the concept of extending projects where it could be demonstrated that costs could be reduced without delaying higher-priority work on other projects, but raised the issue that the cost structure of pipe replacement relative to hydrotesting meant there was less impetus to extend projects for cost savings.[351] D.12-12-030 approved the concept of expanding projects into non-HCA areas where justified.[352]

In VIPER, there is even more reason to approve projects that extend into non-HCA areas since the primary criteria for inclusion are pipe characteristics and disposition for land movement, not population density. Given that the targeted geological conditions are not dependent on, or bound by, the number of people in close proximity, it is reasonable to assume that projects which strive for cost efficiency will extend along the full length of the target geology, and include sections that are not in HCA areas. In discovery, PG&E claimed that no VIPER projects will extend beyond populated areas,[353] in spite of the fact that no projects were engineered when the application was filed,[354] and the fact that PG&E has requested flexibility to change the portfolio of projects as it deems is needed.[355] PG&E's claim that VIPER projects will not extend beyond populated areas also contradicts PG&E's PSEP proposal to take advantage of cost efficiencies, and the fundamental requirements of VIPER to address what is

[349] CPUC SED Reports on PG&E Application Report on PG&E Application A.13-12-012: Ex. ORA-88, July 18, 2014 Preliminary Staff Report; Ex. ORA-143, Excerpt from September 11, 2014 Final Staff Report.

[350] There is a possibility that the Commission will reject PG&E's AOC/TOC methodology and require PG&E to include a measure of the possibility of failure when prioritizing VIPER projects, which could result in projects in less congested areas, and yield lower unit costs than were forecasted or realized in PSEP. However, if it adopts PG&E's AOC/TOC methodology, VIPER will target locations with high consequences if a pipeline should fail, and this is the same locational criteria required for PSEP.

[351] Ex. ORA-86 (DRA Opening Brief in PSEP), pp. 109-110.

[352] D.12-12-030, pp. 66-67.

[353] Ex. ORA-123 (PG&E response to DR-ORA-127 Q1f).

[354] 18 RT 1911 (Barnes/PG&E).

[355] Ex. PG&E-1 (Direct Testimony with Errata, Chapter 4A, Barnes), p. 4A-59.

below the ground. Further, PG&E acknowledged that in VIPER, it will exercise engineering judgement to avoid starting or ending a project in an expensive and unsafe location, such as in the middle of a street, as it did in PSEP.[356] Based on these factors, and the others set forth above, it is highly likely that, contrary to PG&E's claims in this case, VIPER projects will extend to less populated areas.

Fourth, PG&E provided no quantitative evidence to support its claim that the location of VIPER projects increases unit costs relative to PSEP. In its Rebuttal Testimony, PG&E stated that it "is using the fact that there is population in the PIR [Potential Impact Radius] as a factor that points to these typically being higher unit cost projects."[357] In spite of having actual cost project data on 48 PSEP projects completed in 2012 and 2013, PG&E provided no evidence showing how, or even if, unit costs increase as a function of population density.[358] While it is reasonable that unit costs in urban areas will typically be higher than in rural areas, it is counter-intuitive to assume that unit costs increase continuously without limit as population within the PIR increases. It is more likely that unit costs asymptotically approach a ceiling as population increases, similar to how unit costs approach a cost floor as project length increases. However, PG&E has not provided data on this cost function.[359]

Fifth, PG&E's forecast assumes that all projects for large pipes will not only be in "congested " or "highly congested" areas, but located in "super congested" areas with even higher costs. As discussed in Section 7.6.3.3above, this is not a valid assumption.

Sixth, PG&E acknowledged that "the [VIPER] program is designed to implement projects in less and less populated locations over time."[360] Figure 7.6-2 below confirms that this

[356] 18 RT 1940:13-23 (Barnes/PG&E).

[357] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-68.

[358] Ex. ORA-130, cell E66.

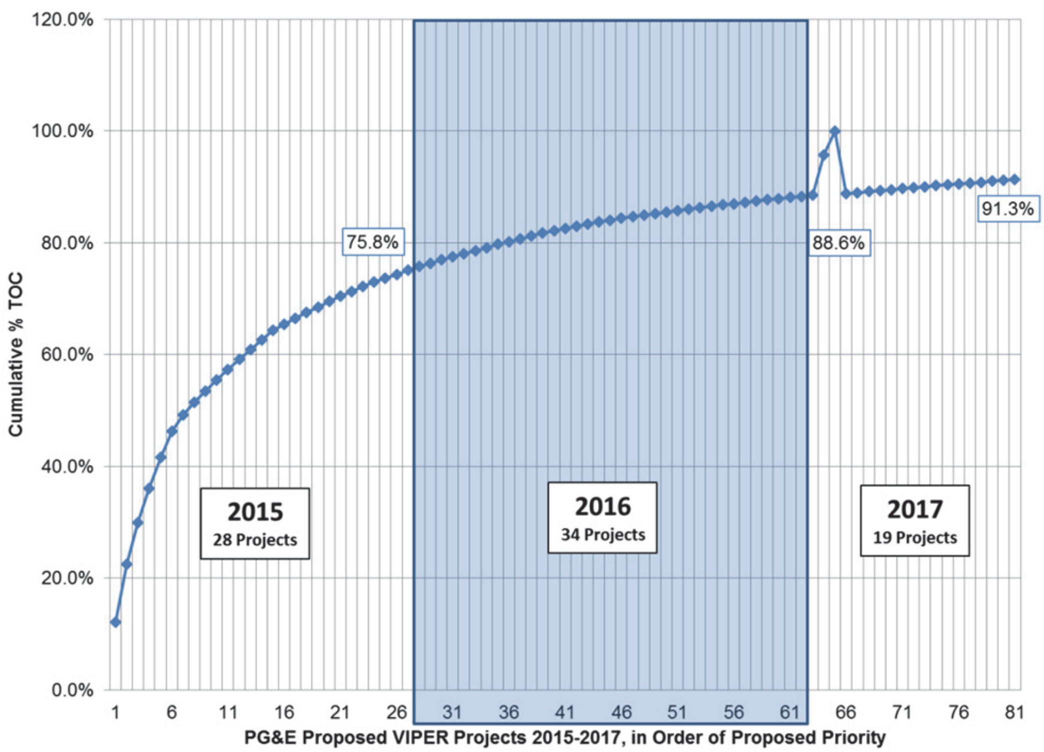
[359] See Ex. ORA-166 (DR-ORA-127 Q5 asked for all evidence and analysis supporting how purported differences in population density impact VIPER unit costs. PG&E response referred to Q1 of the same DR, which included no attachments nor quantitative support.)] Both responses are included in Ex. ORA-166.).

[360] Ex. ORA-80 (PG&E Response to ORA-DR-91 Q20).

change will likely occur within the timespan of the current rate case if PG&E's proposal is approved:[361]

Figure 7.6-2

Cumulative %TOC for PG&E Proposed 2015-2017 VIPER Projects



This chart shows that 75.8% of TOC is reached by the end of 2015. 12.8% is incrementally reached in 2016, and only 2.7% of additional TOC is addressed in 2017, bringing the total TOC addressed by the end of 2017 to 91.3 with significantly diminishing returns post-2015. Since the scope of replacement is relatively constant at 20 miles per year, the reduction in annual % TOC impact can only be due to a lower population within the potential impact radius (PIR) of each project. This indicates that work is performed in progressively less dense or congested areas. This chart shows that while it may be reasonable to assume that the first 10 or

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[361] This chart was prepared by ORA using the % TOC data from PG&E's list of 81 projects in the 2015-2017 time-frame provided in Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), pp. WP 4A-711 to WP 4A-712. See Ex. ORA-80 (PG&E Response to ORA-DR-88 Q4), for an explanation of the anomalous spike at the start of 2017.

even 20 projects are in areas of high congestion, it is not reasonable to assume that the balance of projects in 2015, and all projects in 2016 and 2017 are in high congestion areas. This is further supported by a map provided by PG&E in response to discovery which shows 2015 projects in urban areas like San Francisco, the East Bay, and San Jose, but 2016 and 2017 projects generally in less densely populated locations.[362] For many of the same reasons discussed in Section 7.6.9 and 7.6.12.3 below, a reasonable forecast of pipe replacement costs must account for how costs will decrease throughout the entire rate case period.

Finally, PG&E's definition of "congested" relative to VIPER has changed over the course of this proceeding, and is poorly defined. PG&E's original workpaper supporting its unit costs, Table 7.6-1 reproduced above,[363] referenced specific locations like Sacramento, and both "congested" and "highly congested" locations. In rebuttal, PG&E referred to the "highly congested focus of the [VIPER] program,"[364] but later revised this to "congested focus of the [VIPER] program" without explaining this change.[365] ORA asked multiple discovery questions on this topic, and it appears this change may have been in response to this inquiry,[366] and PG&E ultimately modified this population-based criteria to include projects on large pipes that "have high complexity to complete."[367] Since PG&E did not define "high complexity," ORA probed this issue in hearings. PG&E indicated that it was referring to complexities based on the location of the pipe, such as getting "the rights to do what you need to do."[368] However, PG&E has never provided evidence that costs in one municipality are higher than another, and VIPER proposed projects are located throughout PG&E's service territory.[369] As with many details in PG&E's

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[362] Ex. ORA-123 (Attachment 1 to PG&E Response to ORA-DR-091 Q15.)

[363] The table was provided in Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), p. WP 4A-722.

[364] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), pp. 4A-67 to 4A-68.

[365] Ex. PG&E-49, pp. 4A-67 to 4A-68.

[366] See Ex. ORA-163 (PG&E response to DR-ORA-56 Q5); Ex. ORA-80, (PG&E response to DR-ORA-91 Q20); Ex. ORA-123 (PG&E response to DR-ORA-127 Q1 and Q3); Ex. ORA-166 (PG&E response to DR-ORA-127 Q1, Q2, and Q5.)

[367] Ex. ORA-123 (Revised PG&E responses to DR-ORA-127 Q1 and Q3 dated November 24, 2014.)

[368] 19 RT 2069-2070, (Barnes/PG&E).

[369] Ex. ORA-123 (Attachment 1 to PG&E's response to DR-ORA-91 Q15) provides a map of VIPER projects by year. Attachment 1 to PG&E's response to DR-ORA-88 Q3 provides the city and county of each proposed project, and allows sorting by year and pipe diameter size. See Ex. ORA-92 (ORA

Application, PG&E's definition of the locations in which VIPER will take place has changed over time, and in the end are still insufficiently supported to justify the requested increase in costs.

7.6.7 Comparison To PG&E's PSEP Forecast Suggest PG&E Made A Strategic Decision To Limit Its Showing In This Case

As ORA has observed, PG&E's VIPER unit cost forecasts are more than double what it forecasted in PSEP. While ORA appreciates that some of PG&E's actual PSEP costs have been more than forecasted, PG&E has provided no meaningful evidence that its VIPER forecasts should be any higher than its PSEP actuals, and it has demonstrated complete disinterest in understanding why its PSEP costs were 30% more than forecasted.[370] When compared to PG&E's significant cost showing in the PSEP case, it is hard not to conclude that PG&E has made a calculated decision to limit its showing in this case to limit parties' abilities to challenge its forecast.

Regarding pipe replacement costs, PG&E claims that comparisons between its PSEP and VIPER forecasts are not valid because VIPER projects will be shorter and in more densely populated areas.[371] As discussed in Section 7.6.6.2 and 7.6.6 above, PG&E has not demonstrated that such differences in scope, to the extent they exist, will have a significant cost impact. To the contrary, ORA has shown that any change in scope from PSEP to VIPER cannot justify the significant increase in costs that PG&E forecasts.

Further, it is noteworthy that PG&E's argument against comparisons to the PSEP forecast for pipe replacement are fundamentally different from its arguments against a similar comparison regarding hydrotest costs: PG&E does not state that it is unable to accurately forecast pipe replacement costs.[372] This is consistent with the fact that gas pipeline replacement is a mature process which PG&E and its expert team in PSEP should have been able to accurately forecast in 2011. PG&E's witness in this case agreed that "pipes have been replaced as part of the normal

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Workpaper "WP-ORA-4C-13.xls," tab "ORA-088 Q3-ORA.")

[370] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p.44

[371] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), pp. 4A-66 to 4A-71.

[372] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), pp. 4A-42 to 4A-45.

utility activity for decades"[373] and confirmed that he had no knowledge of "any major advancements in pipe replacement that impact cost."[374]

For these same reasons, D.12-12-030 adopted PG&E's unit cost forecast for pipe replacements, with only minor adjustment. While the Commission found that PG&E's cost forecast for replacing pipeline was at the high end of the range of reasonableness, PG&E's forecast adoption was justified by the Commission because it "is supported by significant operational experience."[375] The only adjustment that D.12-12-030 made to PG&E's forecasted pipe replacement unit costs, as opposed to the overall budget request, was to reduce the escalation rate from the 3.12% requested by PG&E to 1.5%, which impacts each individual unit cost such that the average the unit cost implicitly adopted in D.12-12-030 was less than $4.51 million per mile.[376]

While the Commission adopted PG&E's request for a PMO (with adjustment for the broader 2011 and 2012 disallowances),[377] it denied PG&E's contingency request. It reasoned that the base costs it approved for PSEP were generous, they included the "peninsula adder," and because "PG&E layers on a Program management Office [PMO] that costs about $10 million a year."[378] This denial was also based on policy reasons, such as motivating PG&E to "develop better cost forecasting models" as well as to "improve efficiency and lower overall costs."[379]

Given the amount of analysis involved in developing PG&E's PSEP replacement forecast, and the reasons justifying its adoption in D.12-12-030, the fact that PG&E now seeks unit costs more than double that forecast bears further scrutiny.

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[373] 18 RT 1913: 24-27 (Barnes/PG&E).

[374] 18 RT 1912:5-8 (Barnes/PG&E).

[375] D.12-12-030: pp. 69-70; p.118, FOF 23; p.123, COL 21.

[376] D.12-12-030, pp. 100-101 and p.125, COL 36. It is incorrect to say that the average cost is 1.62% (3.12%-1.5%) lower, since the different escalation rates apply to project costs in 2012, vs. 2013 and 2014, as escalation compounds annually. $4.51 million per mile value from Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p.43.

[377] D.12-12-030, p. 123, COL 27.

[378] D.12-12-030, p. 98.

[379] D.12-12-030, pp. 98 and 100.

Among other things, given the magnitude of the work required and the accompanying costs for the program, PG&E could have and should have prepared a thorough and robust application, capable of meeting the Commission's standard of proof. Instead, PG&E's request for nearly $600 million over the rate case period is supported by only three (3) pages of workpapers, with a sponsoring witness divorced from the process and who therefore could not testify regarding the specific process or projects that went into the forecast.[380] Further, though PG&E had nearly 3 years of PSEP experience and actual cost data available to it, virtually none of it was used to develop or validate its VIPER forecast.

In contrast, PG&E's PSEP application – prepared in less than three months – included more than 750 pages of workpapers and supporting documentation.[381] The cost forecast model was created by an international expert, used construction costs provided by a local contractor, and was validated against PG&E historic data. The cost estimate was prepared by Gulf Interstate Engineering (Gulf), an ISO 9001 quality certified company with a "core competency" in "construction management of pipelines" since it was founded in 1953.[382] Gulf's cost model utilized construction cost data from a local company, ARB, who has since performed 100 of the 255 PSEP hydrotests, and 4 of 61 PSEP replacement projects, completed through March 31, 2014.[383] Finally, Gulf's cost model was validated "based on similar projects escalated to 2011 prices using information from PG&E's Unit Cost Database (UCDB.)"[384]

While ORA raised objections to certain elements of PG&E's PSEP forecast, the point is that PG&E's PSEP forecast was thoughtful, thorough, and transparent. It included quantitative support for many of the unit costs, accounted for a multitude of the variables that impact the cost of a pipeline replacement project, and explicitly stated its contingency request. None of this can be said about the current Application. As described in Section 7.6.2 above, PG&E's VIPER

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[380] See discussion in Section 7.6.2 above.

[381] D.11-06-017 was issued June 9, 2011, and PG&E's PSEP application was filed in response on August 26, 2011. The 750 pages are supported as follows: Ex. ORA-92, PG&E PSEP Workpapers: Vol. 1, pp. WP 3-1 to WP 3-494; Vol. 2, pp. WP 3-494 to WP 3-753. Also, Ex. ORA-85 (PG&E PSEP Prepared Testimony in R.11-02-019, Hogenson), p. 3D-1 to 3E-20.

[382] Ex. ORA-85 (PG&E PSEP Prepared Testimony in R.11-02-019, Hogenson), p. 3D-2 and 3D-7.

[383] Ex. ORA-92, Attachment 1 to PG&E's Response to DR-ORA-89 Q2.

[384] Ex. ORA-85 (PG&E PSEP Prepared Testimony in R.11-02-019, Hogenson), p.3-51.

forecast is simplistic, opaque, and has includes virtually no supporting evidence. Perhaps even more concerning for future GT&S proceedings, the record shows that PG&E has not collected PSEP data such that a better cost model can be developed.[385]

There was ample supporting evidence in the PSEP proceeding for D.12-12-030 to conclude that PG&E's forecast in that case was at the high end of the range of reasonableness. The PSEP actuals were lower than the forecast, by as much as 30%, but an audit would be required to determine if this was due to the forecast being too low rather than PG&E failing to control costs during a program that responded to a crisis. PG&E has also provided no credible evidence to explain the reasons why the PSEP forecast was too low, or to show that pipe replacement costs are increasing.[386] Additionally, further evidence shows trends of falling costs such that actual costs may come even closer to PG&E's PSEP forecast during the rate case period.[387] And PG&E has presented no evidence (bald assertions are not evidence) that VIPER projects are sufficiently different from the PSEP projects to justify a forecast more than 50% above actual PSEP costs.

As described above, PG&E had ample opportunity and ability to prepare a reasonable forecast using PSEP experience and actual cost data, and to document why it believed VIPER would cost so much more than either the PSEP forecast or actuals suggested it should. However, PG&E strategically elected to provide a high level, programmatic, and "anti-analytical" approach in this proceeding, which rejects any comparison to PSEP – whether forecast or actual. As a result, PG&E is left with a showing that does not meet the preponderance of evidence standard used by the Commission to evaluate utility applications. On this basis alone, its VIPER forecast should be rejected.

7.6.8 PG&E's VIPER Program Forecast Incorrectly Applies Its Proposed Escalation Rates

To arrive at its 2015 VIPER forecast of $193.824 million, PG&E essentially escalated each of its three proposed unit costs of $5.28, $5.8, and $13.2 million per mile by 7%.[388]

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[385] 19 RT 2022-2024 (Barnes/PG&E).

[386] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 44.

[387] See discussion in Sections 7.6.9 and 7.6.12.3 below.

[388] Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), p. WP 4A-711, top table. Unit costs from

Assuming the annual escalation used by PG&E for 2012, 2013, and 2014 are correct, the 7% escalation rate is technically correct for actual costs incurred in 2012 only.[389] ORA's data shows this would be appropriate for PG&E's small pipe unit cost, $5.28 million per mile, because it is based on a single project completed in 2012.[390] However, PG&E's unit costs for medium and large pipes include projects completed in 2013 and 2014, and costs for these projects should not have been escalated over three years, as occurs when the 7% rate is used. PG&E should have escalated costs for the individual PSEP project it used to generate unit costs, which would have resulted in a lower overall escalation rate.[391] Further, regardless of the escalation rate PG&E used, Sections 7.6.9 and 7.6.12.3 below which observe that PG&E's hydrotest and replacement costs are falling, explains why ORA does not believe it is appropriate to use any escalation rate for the Hydrotest and VIPER Program forecasts.

7.6.9 PG&E's Claim That Its VIPER Costs Will Increase During the Rate Case Period Is Inconsistent With Its Request For A PMO

During the rate case period, PG&E forecasts that VIPER costs will rise at the same rate as all other capital expenditures: 2.54% in 2016 and 2.65% in 2017.[392] PG&E's Rebuttal Testimony provides arguments attempting to support "upward cost pressures," but provides no quantifiable evidence to support its assertions.[393] In contrast, Sections 7.6.9 and 7.6.12.3 below

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page WP 4A-722 are used to calculate project costs in the lower table on page WP 4A-711, then the sum cost for the 2015 project, $181.144 million, is escalated in the upper table. This is the same as escalating the unit costs.

389 Ex. ORA-80 (PG&E Response to ORA-DR-56 Q15b.) PG&E's response states that 2012 actual costs are escalated, and refers to Attachment 1 to PG&E's Response to DR-TURN-11 Q17 (Ex. ORA-81), which indicates that rates of 1.92%, 2.51%, and 2.39% were used for years 2012-2014 respectively. These rates were multiplied to yield the 7.0% escalation rate PG&E used for to extrapolate its proposed unit costs on page WP 4A-722 to 2015. A lower rate of 4.5% should be used where a 2013 forecasted project cost was used, and 2.39% where a 2014 forecast was used.

390 Ex. ORA 131, p.1, line 4.

391 ORA-34 (Direct Testimony, Corrected Version, Roberts), pp.49-50.

392 Ex. ORA-81, final page, attachment 1 to PG&E's response to DR-TURN-11, Q17, column "Capital Ave." Total escalation in column "Capital" in this table corresponded to the escalation rates used by PG&E for VIPER, as shown in Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), p. WP 4A-711, top table.

393 Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), pp. 4A-75 to 4A-76. Also see Ex. ORA-165 (PG&E response to DR-ORA-128, Q12).

explain why PG&E is likely to realize process improvements and efficiency gains that at least offset any inflation of materials or labor.

PG&E's assertions about rising VIPER costs are also contradicted by its request for $12.75 million a year for a PMO tasked with executing projects and measuring, controlling, and reporting project and program performance.[394] According to PG&E, the PMO will manage the "Alliance contracting [process] including target pricing and validation," and Alliance contract costs are a majority of PSEP pipe replacement costs.[395] Thus, the PMO can play a significant role in controlling costs through process improvements, as evidenced in examples provided in the GT&S Application and the PSEP reports.[396] Given that VIPER is an extension of the reactionary PSEP program, and that VIPER has a smaller and more manageable scope target of 20 miles per year, a competent PMO should be able to continue to initiate and complete cost efficiency projects that, at a minimum, offset PG&E expectations for inflation. If anything, the record shows that PG&E's VIPER costs will be going down, not up, during the rate case period.

7.6.10 PG&E's Forecast Is A "Top-Down" Attempt To Ensure PG&E Shareholders Bear No Risk For Cost Overuns

While PG&E attempts to present its VIPER forecast as a "bottoms-up" analysis that took a subset of PSEP projects that it determined were representative of VIPER projects, added them up, derived a unit cost, and then added an escalator, the evidence belies this impression.

PG&E's cost forecast is based on 81 proposed GTS projects for 2015 through 2017 with significantly different diameters, lengths, and population density based on its own %TOC calculations.[397] However, even with the wide range of projects and proposed unit costs, and a

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[394] Ex. PG&E-1 (Direct Testimony with Errata, Chapter 4A, Barnes), Chapter 9. $12.75 million is the sum of 2015 expense and capex requests, a shown on page 9-19.

[395] Alliance contractor costs represented 68% of PSEP pipe replacement costs. See Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p.47, FN 141.

[396] Ex. PG&E-1 (Direct Testimony with Errata, Chapter 4A, Barnes), p. 9-13. Also, each PSEP report includes a section on PMO "costs and benefits" in section 7, and at least three of these sections conclude with steps taken to "improve project success and increase cost efficiencies." See Ex. ORA-82, page 19 of the April 30, 2014 report and page 20 of the July 30, 2014 report; and Ex. ORA-95, page 20 of the October 30, 2014 report.

[397] Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), pp. WP 4A-711 to WP 4A-712.

stated prioritization based exclusively on "% TOC,"[398] the estimated costs for each of the first three years of the program are exactly the same for each year before escalation: $181.444 million.[399] This suggests that PG&E's forecast was actually developed through a "top-down" process where PG&E determined the revenue requirement it hoped to achieve, and then identified the PSEP projects and unit prices necessary to get there.

While it would be reasonable for a utility to attempt to construct a program with consistent annual funding, it is highly unusual to have the product of actual project lengths and multiple unit costs for the 28, 34, and 19 VIPER projects PG&E proposes for 2015, 2016, and 2017 respectively[400] to sum to the exact same value.[401]

Assuming that PG&E used a top-down approach would certainly explain PG&E's inability to describe why and how the PSEP projects it chose for its database were representative of the VIPER program, and why PG&E's witness knew nothing about those projects. PG&E's process and the factors used to determine its VIPER forecast were, and continue to be, hidden from view.

In hearings, PG&E described that it had not engineered any of the VIPER projects prior to preparing its cost forecast.[402] PG&E also agreed that there was uncertainty in the cost of individual projects and the VIPER program as a whole.[403] In the PSEP Application, PG&E correctly claimed to quantify this uncertainty as the basis of its contingency request.[404] In the current case, PG&E made no attempt to quantify cost uncertainty or define an explicit contingency request, and it testified that its estimate does not include contingency.[405] Clearly,

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[398] "TOC" is "Total Occupancy Count." Please see footnote for a discussion of the meaning and application of % TOC.

[399] Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), p. WP 4A-711, upper small table. ORA confirmed that the total costs for projects in each year, in the larger table on this page and WP 4A-712, each summed to the $181.444 million figure.

[400] See, e.g., Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 35, Table 4C-6 for a summary of the different projects PG&E proposes for each year of the VIPER Program.

[401] See Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 52, Figure 4C-3.

[402] 19 RT 2025 (Barnes/PG&E).

[403] 19 RT 2025-2027 (Barnes/PG&E).

[404] Ex. 88, (ORA PSEP Opening Brief), pp. 110-117.

[405] 19 RT 2030 (Barnes/PG&E).

this is because PG&E provided a high level request that it can comfortably achieve, which means that it included a generous provision for contingency without providing any evidence to support this implicit request.

In short, PG&E's forecast is nothing more than a high-level guesstimate intended to establish a budget that provides PG&E and its subcontractors generous profits.[406] In doing so, PG&E is attempting to foist the cost of uncertainty stemming from its unwillingness to accurately forecast pipe replacement costs exclusively on ratepayers.

If PG&E has provided such a top-down approach to its VIPER forecast – which is what all of the evidence suggests – the rationale for the Commission to reject it is even greater than ORA initially perceived. Not only would PG&E have misled the Commission and parties with its Application, which purports to support a bottoms-up approach, but it would also have no evidence supporting its request. The application is then revealed as a wholly unsupported request to double previously adopted forecasts, complete with a generous but unspecified contingency, to ensure ratepayers rather than PG&E bear the risk of a lack of adequate cost controls, and the cost overruns that will likely occur.

7.6.11 Overview Of ORA's VIPER Program Forecast

Given the lack of data to develop a more sophisticated model to forecast what PG&E's VIPER costs might actually be,[407] ORA's 2015 VIPER Program forecast of $110 million was derived using same simplistic programmatic methodology advocated by PG&E.[408] However, ORA improves on PG&E's modeling by using all PSEP actual cost data from the 42 projects completed in 2012 and 2013, in contrast to the nine projects relied upon by PG&E. To summarize, ORA organized the 42 PSEP projects completed in 2012 and 2013 into small, medium, and large size categories based on diameter,[409] summed the total project costs for each

[406] PG&E's Alliance contracting process includes a collaborative process to establish a "target cost" for each PSEP project each. This process includes an risk/incentive program whereby "under and over runs are shared on a 50:50 basis " between PG&E and the Alliance contractors, so contractors are financially motivated to negotiate a high target cost that they can eventually beat, and receive 50% of the under-run. See Ex. ORA-95, October 31, 2014 PSEP Report, pp. 11-12.

[407] See e.g. 19 RT 2022-2024 (Barnes/PG&E).

[408] In sum, add up all relevant PSEP project costs, divide by the mileage and then multiply the resulting unit cost by the mileage planned for VIPER.

[409] Where data was missing from the PSEP Quarterly Compliance Reports, ORA supplemented with data

category of pipe, and then divided by the number of miles of work each category represented to identify a unit cost per mile for each size category of pipe.[410] Unit costs were then multiplied by the estimated VIPER Project lengths[411] to derive forecasted project costs for VIPER, which were then summed to get the total VIPER Program forecast.[412] ORA's resulting 2015 forecast of $110 million is $83.8 million lower than PG&E's request of $193.8 for 2015.[413]

To test the PG&E forecast, confirm the relative accuracy of its own forecast, and better understand the differences between the ORA and PG&E forecasts, ORA performed the following reviews and analyses:

1. Calculation of actual PSEP unit costs (as described in Section 7.6.12 below), and subsequent comparison to PSEP unit costs calculated by PG&E (as described in Section 7.6.3 above and Section 7.6.13 below);
2. Review of D.12-12-030 orders, regarding both adopted costs and reporting requirements (as described in Section 7.6.13.1 below);
3. Comparison of PSEP forecasts adopted in D.12-12-030 to PG&E's VIPER forecast in this case (as described in Section 7.6.5.1 above);
4. Analysis of cost trends (as described in Section 7.6.9 above and Section 7.6.12.3 below);
5. Comparison of programmatic differences between PSEP and VIPER that could impact cost (as described in Sections 7.6.5 and 7.6.6 above) and
6. Comparison of comparable water pipe replacement costs to PG&E's GT&S forecasted costs (as described in Section 7.6.16 below).

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provided in PG&E data responses.

[410] While ORA calculated unit costs for all three pipe diameter ranges used by PG&E, the values for small and medium diameter pipes were the same, such that ORA ultimately only used two unit costs to derive its 2015 forecast: (1) $3.9 million per mile for pipes 16" and smaller, and (2) $7.2 million per mile for pipes 24" and larger.

[411] This forecast uses the same portfolio of projects proposed by PG&E for 2015, including the project lengths and diameters estimated by PG&E, as provided in Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), Chapter 4A Workpapers with Errata, pp. WP 4A-711 to 712. ORA's use of this data should not be construed as verification or agreement that this is a reasonable portfolio of projects, nor that the data is accurate, since PG&E was not able to provide project specific data on these projects.

[412] Ex. ORA-92, CD, file "WP-ORA-4C-13, ORA VIPER Forecast.xlsx," tab "ORA-088 Q3-ORA."

[413] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 54-55. For reasons discussed in Section 7.6.13.1, ORA did not escalate the actual costs from the 2012 and 2013 projects to derive its 2015 forecast.

As discussed in the Sections cited above, each one of these reviews confirmed the reasonableness of ORA's unit costs, and the resulting 2015 forecast for $110.0 million. In contrast to PG&E's limited showing, as described in Section 7.6.2 above, the breadth and depth of ORA's inquiry and analysis supports the reasonableness of ORA's VIPER forecast and demonstrate that PG&E's simplistic VIPER forecast based on a small cherry-picked data set is unreasonable.

7.6.12 ORA's VIPER Forecast Is Reasonable, And More Generous Than The Adopted PSEP Forecast

The following discussion elaborates on the summary of ORA's forecast methodology provided above (1) to provide more detail regarding the bases for ORA's analysis; (2) to enable a detailed comparison between the ORA and PG&E VIPER forecasts; and (3) to respond to PG&E's criticisms of ORA's forecast.

7.6.12.1 ORA Calculated Unit Costs And The Resulting Forecast Using Two Years Of Actual PSEP Costs Based On Data PG&E Provided In Its PSEP Quarterly Compliance Reports

ORA's Direct Testimony included the following Table7.6-3 which provided ORA's proposed unit costs for replacement of pipes based on the size ranges used in PG&E's VIPER forecast, but using all 42 PSEP pipe replacement projects completed in 2012 and 2013 instead of the 9 projects used by PG&E:[414]

[414] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p.42, Table 4C-10.

Table 7.6-3

ORA Calculation Of Unit Costs Using PSEP Report Data On Completed Replacement Projects

	2012				2013				2012-2013			
Pipe Size (inch)	Projects	Miles Completed	Total Cost ($millions)	Unit Cost ($millions/ mile)	Projects	Miles Completed	Total Cost ($millions)	Unit Cost ($millions /mile)	Projects	Miles Completed	Total Cost ($millions)	Unit Cost ($millions /mile)
<12	3	3.5	$11.043	$3.1	10	2.3	$11.561	$5.1	13	5.8	$22.604	$3.9
12,16	6	3.8	$18.051	$4.7	4	19.7	$74.538	$3.8	10	23.5	$92.589	$3.9
24+	9	6.9	$72.459	$10.6	10	37.1	$243.200	$6.6	19	43.9	$315.659	$7.2
All	18	14.2	$101.553	$7.2	24	59	$329.299	$5.6	42	73.2	$430.852	$5.9

The unit costs derived in the final column of this table were used to develop ORA's 2015 forecast of $110 million. These unit costs and ORA's resulting 2015 forecast are based on the following data:

- All 2012 and 2013 PSEP project costs and milage data as provided by PG&E in PSEP Quarterly Compliance Reports;[415]
- Since PSEP Quarterly Compliance Report data did not include pipe size, pipe size data from PG&E responses to discovery requests was used;[416]
- Only PSEP projects with a tie-in date in the given year were included;[417] and
- Only completed PSEP replacement projects were included.[418]

[415] Data used by ORA is from PG&E responses to ORA data requests, which PG&E indicated is the same as data in the PSEP reports. See Ex. ORA-80, PG&E response to DR-ORA-89 Q2, and Ex. ORA-79, Narrative description of Workpapers, p.16.

[416] Ex. ORA-79, Narrative description of Workpapers, pp.16-17. Attachment 1 of PG&E's response to DR-ORA-64 Q13 (Ex. ORA-80) provided a list of completed projects in a format similar to the Table 11-1 of the PSEP Quarterly Compliance Reports, added the project diameter, but it omitted cost data. Attachment 1 to PG&E's response to DR-ORA-89 Q2 (Ex. ORA-80) provided all Table 11-1 data plus other data fields requested by ORA. ORA merged data from these two attachments and manually added data from other sources where it was missing.

[417] There were no replacement projects completed in 2011, so only 2 full years of recorded data are available – for 2012 and 2013.

[418] In some PSEP Quarterly Compliance Reports and some discovery responses PG&E included retirements, downrates, and transfers within the results for pipe replacement. Language in the proposed settlement for the PSEP Update Application aims to correct this. Projects with retirements, downrates, and transfers are not included in the table above, leading to lower mileage and total cost figures.

7.6.12.2 ORA's VIPER Forecast Does Not Include Costs For Betterment Projects Because Betterments Have A Separate Budget In GT&S

As described above, ORA's VIPER forecast is based on the total cost of 42 PSEP projects as recorded in PSEP Quarterly Compliance Reports. In some PSEP projects, PG&E increased the capacity of a pipeline as a "betterment,"[419] and recorded the betterment to a separate, non-PSEP, account.[420] These betterment costs were not included in the PSEP Quarterly Compliance Reports, and are not included in ORA's VIPER forecast. In contrast, PG&E included over $11.5 million betterment costs in its GT&S forecast, which increased the cost for medium pipes in its rebuttal testimony to $5.55 million per mile from $5.08 million per mile if beterment costs were not included.[421] ORA's forecast has the correct treatment of betterment costs since PG&E has separately requested $21.7 million for betterment projects in GT&S, in addition to the VIPER budget, based on the level of betterment found in PSEP.[422]

7.6.12.3 ORA's Forecast Correctly Incorporates Cost Trends Occurring Between 2012 And 2017

ORA's forecast for 2015 VIPER unit costs does not escalate the 2012 and 2013 PSEP costs upon which the forecast is based. This approach is reasonable because any cost increases due to inflation should be offset by increases in efficiency, and 2015 unit costs should be deflated since ORA has demonstrated that PG&E overestimates VIPER costs in 2016 and 2017.

ORA's Opening Testimony provides evidence that cost increases due to general cost inflation or supply constraints, if considered in isolation, would lead to lower escalation rates than those used by PG&E. Specifically, data from the U.S. Department of Labor shows that consumer and producer prices increased 1.6% to 1.9% annually from January 2011 through June 2014, and prices for steel pipe increased less than 2% total over the entire 3.5 year period.[423]

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[419] Ex. PG&E-2, pp.10-27 to 10-28

[420] For example, compare the "Order Type" for R-003 in PSEP in Ex. ORA-124, excerpt from attachment 1 to PG&E's response to DR-ORA-128 Q9, final two rows of data.

[421] $11.5 million is the difference in the cell E44 values on pages 2 and 3 of Ex. ORA-131. Unit costs are in cell E44 on pages 2 and 3 of Ex. ORA-131.

[422] Ex. PG&E-2, pp.10-27 to 10-28.

[423] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 49.

In comparison, PG&E used higher escalation rates of 1.92%, 2.51%, and 2.39% for 2012, 2013, and 2014 respectively.[424] As described in Section 7.6.8 above, PG&E assumed that all the PSEP costs used in its forecast were 2012 costs, since it applied an escalation rate of 7.0%, which is the compounded product of all three escalation rates above.[425] This is not correct since a majority of the projects included in both PG&E's and ORA's forecasts were completed after 2012.[426] Therefore barring any counteracting trends that would reduce project costs during PSEP, escalation should be approximately 4.4%, not 7%.[427]

ORA Direct Testimony also provided evidence that there were counteracting trends that should have reduced projects cost during PSEP, including that PG&E embarked on a cost savings program in 2013.[428] In addition, PG&E's PSEP Reports are filled with narratives of the benefits that were provided by the PMO, including activities that "increase cost efficiencies."[429]

ORA's Direct Testimony also provided three reasons why VIPER costs in 2015 and beyond should actually be lower than PSEP costs.[430] First, the VIPER Program proposes a moderate rate of work compared to the pace of PSEP. Any inefficient processes or contractors that were required to meet the higher PSEP pace can be corrected or eliminated. This should lead to lower costs. Second, VIPER promises high value construction work performed at a moderate rate of installation over 11 years. The VIPER Program will provide a steady income stream for construction contractors, and PG&E should be able to leverage the desirability of this fact to negotiate lower prices and less risk. Third, by prioritizing projects based on the % TOC

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424 Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 49.

425 Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p.50. The small table at the top of Ex. PG&E-5 (Chapter 4A Workpapers, Vol. 2, Barnes), p. WP 4A-711, shows that PG&E used an escalation rate of 7.0% to derive its 2015 VIPER forecast.

426 Ex. ORA-131, p.1. "Project Comparison" provides the tie-in data for all projects used by PG&E and ORA, and shows that only four of nine projects PG&E used to establish its unit costs were completed in 2012, and 19 of the 42 projects ORA used were completed in 2012.

427 This assumes annual inflation of 1.75%, the mid-point between 1.6% and 1.9% above, and that 50 % of projects were completed in 2012 and 2013, and escalated 5.34% and 3.53% respectively.

428 Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 48.

429 Section 7 of each PSEP Report provides "PMO Costs and Benefits." Ex. ORA-82 (April 30, 2014 PSEP Report), p.19, states "finally, the PMO's role includes many activities…designed to improve project success and increase cost efficiencies."

430 Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 48.

metric PG&E proposes, replacement should occur in progressively less congested locations over the life of the program.

PG&E agrees with this last point, which further emphasizes the appropriateness of ORA's decision not to provide for escalation in its forecast.[431] Notwithstanding this fact, PG&E and ORA have stipulated to increases of 2.3% and 2.6% for 2016 and 2017 respectively for Capital Additions.[432] Thus, this stipulation will result in increased budgets for VIPER in 2016 and 2017 relative to whatever funding the Commission approves for 2015. PG&E's agreement that its %TOC prioritization methodology results in projects is less populated locations over time, and corresponding cost reductions, suggests that the 2015 starting point for any forecast should therefore take these falling costs into account.[433]

In addition, PG&E's PMO will continue into VIPER and should continue to improve the pipeline replacement process and increase cost efficiencies similar to the gains PG&E claimed for PSEP. These factors should reduce VIPER costs in 2016 and 2017.

Assuming that the stipulation is adopted by the Commission, it is reasonable to approve a lower budget for 2015 to provide the correct level of funding for the entire three year rate case period. For example, ORA's VIPER forecast is for $110.0 million each year with no escalation, or $330.0 million for the rate case period. However the attrition year stipulation would result in an increase to $112.5 in 2016 and $115.5 in 2017 for a three year total of $338.0 million. To provide a three year total of $330.0 million given the attrition year stipulation, the 2015 budget should be reduced to $107.4 million.[434] ORA has not, however, revised its 2015 VIPER forecast from $110.0 million, so the overall impact of the attrition year stipulation is to provide extra budget, $8 million over three years, to PG&E beyond what is supported by the record.

In Rebuttal Testimony, PG&E claimed that "ORA"s assumptions underlying the elimination of escalation are not consistent with actual cost trends," but provides no evidence to

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[431] Ex. ORA-80 (PG&E Response to DR-ORA-92 Q20.)

[432] Ex. Joint Stipulation-3, p.27.

[433] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 51-53. In Ex. ORA-80 (PG&E response to DR-ORA-92 Q20), PG&E states that "the [VIPER] program is designed to implement projects in less and less populated locations over time."

[434] This would provide $109.9 million in 2016 ($107.4 * 1.023), and $112.73 million in 2017 ($190.9 * 1.026).

support this assertion.[435] In contrast, ORA has shown why it is not appropriate to escalate PSEP project costs to forecast 2015 VIPER causes due to declining costs trends in both PSEP and VIPER (Section 7.6.9). Even if the Commission does not agree with ORA's qualitative support demonstrating declining, not increasing costs as escalation suggests, it should adopt ORA's quantitative support for a 4.4% escalation rate for projects completed in 2013 as compared to PG&E's 7.0% rate, as set forth herein and in Section 7.6.9above.

7.6.13 PG&E's Rebuttal Criticisms Of ORA's Forecast Have No Merit

In Rebuttal Testimony, PG&E offered the following criticicms of ORA's VIPER forecast:

1. PSEP actual pipe replacement costs are not appropriate for GT&S because VIPER will include shorter projects in more congested areas;[436]
2. The cost data ORA used was "incomplete" and did not include "programmatic costs;"[437]
3. ORA "used incomplete cost data that was inappropriately integrated;"[438] and

PG&E also provided a separate version of ORA's Table 4C-10 (reproduced as Table 7.6-3 above), which it claimed demonstrated that actual PSEP pipe replacement costs were "very much in line" with its VIPER forecast.[439]

Each of PG&E's criticisms is addressed in the following sections.

7.6.13.1 ORA's Reliance On the PSEP Data Provided In the PSEP Quarterly Compliance Reports Is Reasonable And Appropriate

Similar to its criticisms of ORA's Hydrotest forecast, PG&E criticizes ORA's use of the PSEP Quarterly Report Data, claiming that the data was "incomplete" or missing "full project costs."[440] For the reasons discussed in Section 7.4.4 above, this criticism has no merit.

[435] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-78

[436] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), pp. 4A-66 to 4A-71.

[437] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-73.

[438] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-73.

[439] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-74.

[440] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-73.

A basic premise of ORA's Direct Testimony was that data provided by PG&E to the Commission pursuant to a direct order should be the most accurate and complete data available regarding PSEP program costs. This is the primary reason ORA's VIPER forecast is based on data contained in the PSEP Quarterly Compliance Reports.[441] As described in Section 7.4.4.1 above, D.12-12-030 ordered PG&E to provide the PSEP data in the form of the PSEP Quarterly Compliance Reports to the Commission, the parties, and the public, in order to have accurate cost information about PSEP program implementation, and explanations of any significant deviations in those costs.[442] It is appropriate for the Commission and parties to assume that PSEP program cost information filed with the Commission pursuant to a Commission order is complete and accurate and can be relied upon to forecast similar future program and project costs.

It is inappropriate for PG&E to criticize ORA for its reliance on this data. To the extent information in the PSEP Quarterly Reports is missing or inaccurate, Rule 1.1 sanctions may be imposed on PG&E for these failures. Vintage Pipe Replacement

7.6.13.2 ORA's Analysis Includes All Programmatic Costs Included In the PSEP Quarterly Compliance Report

PG&E's claim that ORA's analysis did not include "programmatic costs"[443] is based on its claim that the PSEP Quarterly Compliance Report data did not include "programmatic" costs. This claim is inconsistent with the record in the PSEP proceeding – which shows that program costs were incorporated into project costs. It is also inconsistent with the assumptions made in D.12-12-030, and with PG&E's obligation to report all PSEP costs in its Quarterly Compliance Reports.

PG&E's detailed PSEP forecast integrated all indirect, overhead, and management costs for the PSEP pipe replacement program within the cost forecast for each of the 168 proposed

[441] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 19.

[442] See D.12-12-030, p. 86, FOF 39: "To keep the Commission, the parties, and the public informed of PG&E's progress and actual cost experience, we will require PG&E to file and serve compliance reports. … The information required will include comparisons of actual versus authorized cost for each work project as well as explanations of any significant deviations. Schedule and prioritization changes will also be included." See also D.12-12-030, Ordering Paragraph 10, p. 128, and Attachment D.

[443] Ibid, p.4A-73.

projects. PG&E's "programmatic" forecast of $844 million for PSEP pipe replacement was simply the summation of the 168 individual project cost forecasts.[444] D.12-12-030 adopted PG&E's forecast, except for additional disallowances and adjustments to escalation previously discussed, which reduced the costs for many of the 168 projects, and reduced the programmatic budget to $796 million.[445] With the exception of the PMO, which was separately approved by D.12-12-030, at no time in the PSEP proceeding did PG&E identify "programmatic" costs outside of the forecasted project costs. To the contrary, D.12-12-030 explicitly states that the costs adopted were for programs, not projects, in Finding of Fact 39.[446]

7.6.13.3 PG&E Makes Misleading Claims That ORA Had Data Integration Issues And Used Incomplete Cost Data

PG&E claims that ORA "used incomplete cost data that was inappropriately integrated" to develop its VIPER forecast.[447] There is no merit to these claims.

The first part of this claim relates to the Quarterly Compliance Report cost data ORA used, and the issue of "programmatic" costs discussed above. However, PG&E also claims that ORA's use of the "tie-in" date to represent the project completion date "was an incorrect usage of that data," such that ORA "missed some costs in their analysis, causing unit costs to become inappropriately deflated."[448]

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[444] See Ex. ORA 92, PG&E Workpapers Supporting PSEP Chapter 3, pp. WP 3-2 to WP 3-6, Table 2. Lines 1 through 170 provide the costs for each of the 168 proposed projects, excluding line 3 which is a subtotal and line 4 which is blank. The subtotals from line 3 ($.609 million) and line 170 ($833.563 million) are carried forward to Table 1 on page WP 3-1, which shows the total cost to ratepayers for both StanPac and PG&E owned pipeline replacement projects. This does not include $9.8 million for project costs that PG&E proposed not to collect from ratepayers, for a total program cost of $843.972 million ($833.563+$.609+ $9.8). See also Ex. ORA-85 (PG&E PSEP Prepared Testimony in R.11-02-019, Hogenson),p. 3-66.

[445] Ex. ORA-176, Late-filed Ex. ALJ-5, tables 1 and 2.

[446] D.12-12-030, p.120, "The amounts [approved for rate recovery] in Attachment E are *program-based* upper limits on expense and capital costs to be recovered from ratepayers for the specific projects authorized through the implementation plan," emphasis added.

[447] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-73.

[448] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-73.

The PSEP Reports use the tie-in date to determine which projects to include in the report of completed costs, so ORA reasonably did the same.[449] PG&E's witness also confirmed that a pipeline is generally tied-in before it can be operational.[450]

PG&E claims there were additional costs incurred for some projects after the tie-in date, such that ORA's analysis improperly excluded them. However, PG&E does not quantify these costs. Any excluded costs were the result of ORA reliance on PG&E's Quarterly Compliance Report data, which ORA reasonably assumed was complete. Further, while PG&E made the same criticism regarding ORA's Hydrotest forecasts, and claimed "over $2 million" in costs associated with this issue (claims which ORA shows are inaccurate),[451] PG&E's failure to quantify those costs here suggests the costs were similarly small (or even smaller) for pipe replacements, i.e,. no more than 0.5% of the program costs.[452]

PG&E's Rebuttal Testimony also made misleading claims that ORA had data integration issues.[453] In Answer 223 PG&E misquotes ORA's workpaper narrative, which discussed why ORA used data <u>comparable</u> to the PSEP Quarterly Compliance Report data, rather than data from the reports themselves.[454] In fact, the only integration performed by ORA was to supplement the cost data in one PG&E data response with pipe diameter data from another, and this was an easy process, with no errors observed by ORA or PG&E.[455] PG&E's Answer 229

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[449] Ex. ORA-82 (April 30, 2014 PSEP Report), pp. 26, Table 11-2: "Tie-In Date" is described as "Project Finish Date."

[450] 19 RT 1988 (Barnes/PG&E).

[451] See Ex. ORA-47 (Supplemental Testimony, Roberts), pp. 19-20. See also the discussion in Section 7.4.4.4 above related to the Hydrotest Program.

[452] PG&E's response to ORA DR-123 Q11 indicated that "the addition of over $2 million to the costs reported in the PSEP Quarterly reports are from 2011 through the second quarter (Q2) of 2014 for those costs that were completed and tied-in by the submission of the year end 2013 report, i.e. the Q4 2013 quarterly Pipeline Safety Enhancement Plan (PSEP) report." See Ex. ORA-94. Ex, ORA-47 (Supplemental Testimony, Roberts), p.19, Table 4C-S-6, line 1 shows that this variance was actually $1.947 million, on a total cost of $480 million, or a change of 0.4%.

[453] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), pp. 4A-73 to 4A-74.

[454] Ex. ORA-79, Narrative of Workpapers, p.16, ll. 6-10.

[455] Ex. ORA-79, Narrative of Workpapers, pp. 16-17.

explains that PG&E "could not use the same merged data set," but does not indicate that any specific integration errors were observed.[456]

7.6.13.4 ORA's Forecast Properly Considered All Projects, Not Just Those Located In "Congested" Locations

Finally, PG&E criticizes ORA's forecast for including projects that were not located in "congested" locations.[457] PG&E's observation is correct, but has no merit. As repeatedly explained, ORA included data for all projects completed in 2012 and 2013. Thus, ORA included "highly congested" projects, as well as "congested" projects, or any other project completed between 2012 and 2013. The rationale for using the large data set available to it, rather than a small subset of data, has been discussed throughout both this Section 7.6 and Section 7.4. Further discussion is provided in Section 7.6.14 below, and the exact impact of including this data to calculate unit costs is provided in Ex. ORA-131.

7.6.14 PG&E's Efforts To "Correct" Or "Duplicate" ORA's Methodology By Showing That Using More Data Verified Its Own Forecast Perpetuates The Cherry-Picking Errors In PG&E's Forecast

In Rebuttal Testimony, PG&E attempted to respond to ORA's criticisms that PG&E did not include enough data in its analysis by purporting to "duplicate" ORA's analysis "to see if it came to similar conclusions."[458] (This is the same "validating analysis" discussed in Section 7.6.3 above.[459]) In sum, PG&E supplemented its original analysis of nine projects with an analysis of 35 projects that excluded two projects included in the original analysis.[460]

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[456] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-74.

[457] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-73.

[458] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-74.

[459] Issues raised by PG&E's "validating" analysis are also addressed in Section 7.6.3 above, which provides more specifics of how PG&E modified its original VIPER forecast to incorporate new projects, and the problems with those efforts. The following discussion provides additional insight as it relates to PG&E's criticisms of ORA's VIPER forecast, and why those criticisms have no merit.

[460] Projects R-006 and R-061were included in PG&E's original nine projects, and 15 projects supporting errata testimony, but were not included in the original or revised versions of Table 4A-13.

While PG&E did not revise its VIPER forecast as a result of this analysis, PG&E concluded that the analysis shows that its "proposed unit costs are very much in line with the nine projects analysis for 'congested' work areas that PG&E used to develop the GT&S forecast, with very minor variation."[461]

It is noteworthy that PG&E was required to revise this analysis in response to issues raised by ORA, such that the PG&E's Rebuttal Table 4A-13, capturing the results of the analysis, had to be replaced. Reproduced below is PG&E's more current version of Table 4A-13:[462]

TABLE 7.6-4

PG&E Unit Cost Summary From Rebuttal, Original and Revised Versions

Diameter Range (inch)	GT&S Application and Recommended Unit Cost (M$/mi)	ORA Calculated Unit Cost in Table 4C-10	PG&E Table 4A-13 Unit Cost (M$/mi)	PG&E Table 4A-13, R2, Congested Unit Cost (M$/Mi)
< 12	5.3	3.9	5.5	5.5
12" to 20	5.8	3.9	5.8	5.6
≥ 24	13.2	7.2	12.2	12.3

Diameter Range (inch)	GT&S Application, # of projects	ORA Table 4C-10, # projects	PG&E Table 4A-13, # of projects	PG&E Table 4A-13, R2, # of projects
< 12	1	13	16	14
12" to 20	4	10	14	11
≥ 24	4	19	10	10

Also notable about this table is PG&E's characterizations in the title of the table, which refer to ORA's "Flawed Unit Cost Calculation" and PG&E's "Unit Cost Calculation Using Correct Data And ORA Method." This title is misleading. The only difference between ORA's VIPER forecast and PG&E's various forecast iterations is the data used. As discussed in the previous section, PG&E has provided no evidence showing that the data relied upon by ORA was "flawed" or "incorrect" compared to the PSEP Reports and discovery responses from which

461 Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-74.

462 See Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), Rebuttal, p. 4A-74, Table 4A-13. Ex. ORA-124 includes revision 2 of Attachment 1 to PG&E's response to DR-ORA-128 Q9, which is a revised version of this table, and PG&E's supplemental response to DR-ORA-128 Q9, which provides the issues that led to this revision. The table provided here excludes data for PG&E Table 4A-13 R1, which was an iteration performed by ORA that was not adopted by PG&E.

ORA obtained data to support its analyses. As confirmed by a PG&E data response discussed below, the only debate between ORA and PG&E is which data points should be used – all of the PSEP data on pipe replacements for projects completed between 2012 and 2013, as used by ORA, or a cherry-picked subset of data spanning 2012 through 2014, as used by PG&E.

Further, PG&E's Table 4A-13, reproduced above, shows that using the 35 projects PG&E ultimately relied upon to "validate" its VIPER unit cost forecasts demonstrates that PG&E's forecast for large pipes should be reduced by approximately $1 million per mile.[463]

PG&E's "validating" analysis prompted an ORA data request: are PG&E's calculated unit costs significantly higher than those calculated by ORA because ORA used different data (e.g. project costs or lengths), or because PG&E included different projects in its analysis? The answers can be found in Ex. ORA-131, which compared the data used to generate the last column of PG&E's Table 4A-13 (the expanded "verifying" data of 35 projects) and ORA's unit cost forecasts provided in Table 4C-10, reproduced above as Table 7.6-3.[464]

Exhibit ORA-131 shows that: (1) the largest impact on unit costs was PG&E's exclusion of projects with large diameters that were not on Line 109; (2) the source of data had a small impact on all unit costs; (3) PG&E's inclusion of projects completed in 2014 had a significant impact on the unit costs for small and medium pipes; and (4) the inclusion of betterment costs in PG&E's calculations had a significant impact on the unit cost for projects with medium sized pipes. More specifically:

1. For large pipes, the main reason PG&E's unit cost is 71% higher than ORA's forecast is that PG&E excluded all projects, including six classified as congested, that were not on Line 109;[465]

2. Data differences accounted for a no more than 15.8% impact on the unit costs if "betterment" costs are included;[466]

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[463] PG&E used $13.2 million per mile in the application, vs. $12.2 in the first revision of Table 4A-13, and $12.3 million per mile in the final revision.

[464] Ex. ORA-131.

[465] From row 68 of Page 2 of Ex. ORA-131, ($12.3-$7.19)/$7.19 = 71%. Page 1 of Ex. ORA-131 shows that six of the excluded projects were classified as congested, while three were classified as rural. Page 2 of Ex. ORA-131, Column J, show that the excluded projects had a wide range unit costs.

[466] Ex. ORA-131, page 2 includes "betterment" costs in Column B. Row 22 shows the units costs for small pipes for 11 projects common to both analyses, and that the difference in unit costs is 2.5% (($4.15-$4.05)/$4.05). Row 45 shows the units costs for medium pipes for 8 projects common to both analyses,

3. Data differences accounted for no more than a 2.5% impact on the unit costs if "betterment" cost are not included;[467]

4. For small pipes, the main reason PG&E's unit cost is 41% higher than ORA's forecast is that PG&E included three projects that were tied-in in 2014;[468] and

5. For medium pipes, the main reason PG&E's unit cost is 29% higher than ORA's forecast, when betterment costs are excluded, is that PG&E included three projects that were tied-in in 2014.[469]

As discussed in Section 7.6.12.2 above, betterment costs should not be included in any VIPER forecast because betterment projects are funded through a separate program in GT&S. PG&E's reliance on projects completed in 2014 is discussed in Section 7.6.3 above. While ORA's analysis did not include 2014 data since only one quarter of data was available, it is possible that 2014 generally included projects that were delayed for various reasons that increased costs. Finally, Section 7.6.3.3 above discusses why there is no justification for PG&E to use only projects on Line 109 in its forecast of large pipe unit costs.

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and that the difference in unit costs is 15.8% (($4.26-$3.68)/$3.68). Row 69 shows the units costs for large pipes for 10 projects common to both analyses, and that the difference in unit costs is 2.2% (($12.3-$12.03)/$12.03).

[467] Ex. ORA-131, page 3 removes "betterment" costs in Column B, as indicated by cells highlighted in yellow. Row 45 shows the units costs for medium pipes for 8 projects common to both analyses, and that the difference in unit costs is 0.2% (($3.67-$3.68)/$3.68). Betterment costs impacted only medium pipe calculations, so the unit costs for small and large pipes are unchanged, and the larges difference of 2.5% for small pipes becomes the largest difference.

[468] From row 21of page 2 of Ex. ORA-131, ($5.50-$3.90)/$3.90 = 41%. The primary driver is project R-056 in line 7 due to its length of 5.12 miles, which is 40% of the total length of 12.76 miles for all projects included in PG&E's revised analysis. A secondary driver is that ORA included two projects that PG&E classifies as "rural" and that PG&E did not include in the revised version of its Table 4A-13. However, these two projects total 0.40 miles in length, which are only 6.9% of the total length used in ORA's calculations, and has less impact of the average unit cost.

[469] From row 44 of Page 3 of Ex. ORA-131, ($5.08-$3.94)/$3.94 = 29%. ORA's forecast includes two projects that PG&E classifies as "rural" and that PG&E did not include in the revised version of its Table 4A-13. However, these projects (R-073 and R-133, lines 36 and 40 respectively) had unit costs higher ($7.85 and $4.81 respectively) than ORA's average unit cost ($3.94), so their inclusion actually reduced the cost difference between the two analyses.

7.6.15 All Of The Evidence Shows That PG&E's Decision To Use Only 9 PSEP Projects To Support A Nearly $600 Million Program Is Unreasonable; In Contrast, ORA's Forecast Is Well-Documented And Supported And Should Be Adopted

ORA's forecast is based on data from the PSEP Quarterly Compliance Reports that should include all reasonable costs PG&E incurred replacing pipelines in 2012 and 2013. Even if the PSEP Quarterly Compliance Reports do not include all costs for each project, the omitted costs have only a minor impact on calculated unit costs.[470] The majority of the difference in the unit costs calculated by ORA and PG&E is due to the projects included in each of the competing calculations. ORA included all pipe replacement projects completed in 2012 and 2013, using the most reasonable definition of "completed," and did not remove any of these projects for any reason. In contrast, PG&E used an ill-defined definition of "completed" to include projects completed in 2014, some of which had exceptionally high unit costs, and it filtered out projects it considered to be in areas less populated than those planned for VIPER. As discussed in Section 7.6.13.4 above, PG&E provides no defensible explanation for its exclusive focus on "congested" projects in VIPER, and there is ample evidence, including PG&E's agreement that VIPER projects will be located in less congested areas over time.[471]

7.6.16 Water Pipeline Replacement Unit Costs Provide A Benchmark For Considering The Reasonableness Of VIPER Unit Cost Forecasts

In order to provide context for both the PG&E and ORA proposed unit costs for the Viper Program, ORA analyzed the costs to replace water pipelines in the San Francisco Bay Area.[472] ORA acknowledges that comparison of data between industries can be difficult, but notes that PG&E has used comparisons to the airline, railway, automotive, and other industries in this Application in support of its benchmarking efforts.[473] Further, when ORA attempted to perform

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[470] 2.5%, per item 3 on the previous page.

[471] Ex. ORA-80 (PG&E Response to ORA-DR-91 Q20).

[472] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), section 3.3.4.4, pp.44-47 and Ex. ORA-79, Narrative Description of Workpapers, pp. 18-22.

[473] Ex. PG&E-1 (Direct Testimony with Errata, Chapter 1, Stavropoulos), p. 1-17.

a comparative analysis to the costs of replacing gas pipelines in other areas in the PSEP proceeding, PG&E complained that those areas were not comparable to performing work in the locations covered by PG&E's service territory.[474] With comparison to other gas company costs eliminated by PG&E, ORA felt it had no choice but to consider similar industries operating within PG&E's service area.

ORA's Direct Testimony described the process used to select water pipeline projects performed in the San Francisco Bay area as a benchmark for gas pipeline replacement costs, and summarized the reasons the comparison is valid:[475]

- Water mains use some of the same pipe diameters as gas lines;
- Water mains and gas pipelines often share the same right of way;
- Water and gas line networks are comparable in terms of having transmission, distribution and customer service lines of decreasing diameter;
- For water mains made of welded steel, the project life cycle from planning through tie-in is essentially identical to that of gas transmission lines; and
- Water utility data in PG&E's most dense population centers was publicly available.

ORA's Direct Testimony also observed that there is no apparent reason why replacing the <u>same</u> length and diameter of pipe in the <u>same</u> location should have significantly different planning, permitting, design, customer outreach, project management, construction management, provision for customer outages, trenching, shoring, material transportation, mitigation of conflicts with other utility pipes, traffic management, work hour restriction costs, or remediation costs.[476] As will be subsequently discussed, PG&E provided no rebuttal testimony that these activities, which logically are major cost drivers, are significantly different for gas as compared to water pipe replacement.[477]

ORA compiled and analyzed data for water mainline replacement projects performed for the San Francisco Public Utilities Commission (SFPUC) and East Bay Municipal Utility District

[474] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 45:13-21.

[475] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), pp. 45-46.

[476] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 44.

[477] As discussed below near the end of this section, PG&E's witness stated in hearings that safety and public outreach is more involved for gas pipelines, which would impact some of these activities.

(EBMUD) which are included in the ORA Exhibit 4C Workpapers.[478] These workpapers describe the data used, how the projects were selected for inclusion in ORA's analysis, and limitations in the comparisons. In particular, the workpapers describe that the pipelines installed by SFPUC are all ductile iron pipes rather than welded steel, and how the savings from avoiding welding must be compared to the material costs for iron pipes which could be higher due to the mechanical couplings that are integrated into the pipe sections.[479]

The following Table 7.6-5 compares the results of this analysis for steel and ductile iron water main replacement projects to PG&E's pipe replacement costs:

Table 7.6-5[480]
Comparison Of SFPUC, EBMUD, PSEP, and GT&S Pipe Replacement Unit Costs
(In Millions Per Mile)

Pipe OD	SFPUC Actuals	EBMUD Actuals, Excluding Projects with RR Crossings[481]	PSEP Forecast	PSEP Actuals	PG&E GT&S 2015 Forecast
<20"	$1.6- $1.79	$1.43 -$2.21	$3.9 - $4.0	$3.9	$5.28 - $5.8
>20"	$2.95[482]	$4.81 -$6.41	$5.6 - $6.6	$7.2	$13.2
All	NA[483]	NA[484]	$4.5	$5.9	$9.7 ($9.0 - $12.3)[485]

478 See Ex. ORA-79 (Narrative Description of Workpapers), pp. 18-22. MS Excel workpapers are described in this narrative and are provided in native format in Ex. ORA-92.

479 Ex. ORA-79 (Narrative Description of Workpapers), pp. 21-22.

480 Source: Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p. 46, Table 4C-13.

481 EBMUD data included a project with 270 feet of 12" pipe that had a unit cost of $11.69 million per mile, and a project with 290 feet of 30" that had a unit cost of $9.68 million per mile. Unit costs for these projects were excluded from this table because they involved railroad track crossings. However, even these short projects with special circumstances were less expensive per foot than the average unit cost forecasted by PG&E for large pipes.

482 Data was only available for one project with pipe larger than 20" OD, and this project had 7,135 feet of 24" pipe and 6,050 feet of 4", 6", and 8" pipe. The project cost provided is for all pipe, and would likely be higher if the entire project was for 24" pipe.

483 Data for SFPUC and EBMUD shows the range of individual project unit costs, subject to the footnotes provided. PG&E data are average unit cost for all three groups of data.

484 Data for SFPUC and EBMUD shows the range of individual project unit costs, subject to the footnotes provided. PG&E data are average unit cost for all three groups of data.

485 The $9.7 value used PG&E's target length per year of 20 miles, and PG&E's request for $193.8 million in 2015. The lower unit cost of $9.0 million per mile is based on the approximate length of projects proposed for 2015, 21.6 miles, and the higher value is based on the approximate length of

This data demonstrates that the *average* unit costs for PG&E gas pipeline replacement across its entire service area, which should be average values that account for the full spectrum of unit costs, low to high, are significantly more expensive than the unit costs for water main replacement in two of the most populated areas within that service territory.

While a comparison between the cost to replace water and gas pipelines may not provide a purely "apples to apples" comparison, the data compiled by ORA should prompt the Commission to ask "why does it cost so much more to grow an apple than an orange and deliver it to the same customer?" PG&E has not provided the evidence required to show that the replacement of gas pipelines is significantly more expensive than for comparable water pipelines.

Instead, PG&E argues that comparisons to water pipe replacement are not valid. In Rebuttal Testimony, PG&E: (1) states that "labor, construction, and materials requirements are significantly more expensive;" (2) summarizes the "main differences between water mains and natural gas transmission pipelines;" and (3) concludes that comparisons to water pipe replacement costs are is "not appropriate."[486] PG&E also states that ORA inappropriately excluded certain projects from its analysis.[487] These claims are unsupported and/or wrong.

First, PG&E's claim that the costs for gas pipeline replacement are "significantly more expensive" is unsupported, since PG&E provided no comparative cost data and stated that "there is no need to seek cost analysis information from another industry."[488] (But recall that in PSEP PG&E complained comparisons to any other gas provider were inappropriate). In addition, PG&E's claim that cost differences are "significant" does not appear consistent with the magnitude of cost impact for the "major differences" claimed by PG&E. Three of the differences are due to hydrotesting, which encompasses much less than 10% of the cost of a pipe replacement project.[489] PG&E does not suggest that water mains do not require a hydrotest, and

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projects proposed for 2017, 16.6 miles, and the 2017 forecasted cost of $204.0 million.

[486] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), pp. 4A-76 to 4A-77.

[487] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-78.

[488] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-77.

[489] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-77, ll. 3-8. PG&E's

that this entire cost is not included, but rather that the requirements are less stringent. ORA agrees that it would be less expensive to hold pressure for 2 hours than for 8 hours, but does not believe that the cost of the 6 additional hours is significant compared to the weeks or months that construction crews are working to hydrotest a pipeline following a replacement project.[490]

The remaining issues raised by PG&E in rebuttal relate to material and welding costs.[491] For the later, PG&E cannot quantify what portion of the cost of pipe replacement is attributable to welding and inspection of welds, so it is not possible to determine if different standards have a cost impact, let alone whether the difference is significant.[492] Regarding materials, PG&E references standards for water agencies outside its service territory, and irrelevant information about plastic pipe joints to support its claims that materials are significantly higher for gas pipelines.[493] However, PG&E has indicated that materials account for approximately 6% of PSEP pipe replacement costs,[494] and that the pipe coating is generally included within the material cost.[495] Therefore, even if pipe, pipe coatings, and other materials are different for steel water pipelines, these differences have a maximum cost impact of 6%. This maximum will not be achieved because the same basic materials are used in both cases: coated steel pipe. In addition, PG&E's rebuttal fails to note that some of the differences increase the cost of water mains compared to gas pipelines. For example, water mains are coated on the interior of the pipe

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estimates for hydrotest projects are approximately one-tenth the cost it estimates for replacement projects: In PSEP, $.502 M/mile vs. $4.51 M/mile; in GT&S for 2015 $1.02 M/mile vs. $9.65 M/mile ($193.8 million/20 miles). These figures are for a separate hydrotest project rather than a hydrotest performed as part of a replacement project. In the latter case, which is of concern in this situation, many costs including permitting, mobilization, excavation, shoring, excetera, will be part of the replacement process and not part of the hydrotest cost. Therefore, the portion of a replacement project attributable to hydrotesting should be much less than 10%.

[490] See Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-77:3-4.

[491] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-77:9-19.

[492] Ex. ORA-122 (Response to DR-ORA-122 Q2). ORA's expert witness in the PSEP proceeding estimated welding costs to be less than 3.5% of variable $ per foot for pipe costs in highly congested areas. See Ex. ORA-86 (Direct Testimony of ORA Witness Delfino), p. 1-13. This percentage would be lower if fixed costs are included.

[493] Ex. ORA-122 (Response to DR-ORA-122 Q3).

[494] Ex. ORA-122 (response to DR-ORA-122 Q1).

[495] 18 RT 1928:14-23 (Barnes/PG&E). The bulk of coating costs is a part of the purchased pipe, but the portion adjacent to girth welds is installed in the field.

as well as the exterior, and the "bells" on bell and spigot joints referenced by PG&E require an additional manufacturing step which likely increases material costs.[496]

PG&E also incorrectly states that ORA's analysis excluded EBMUD projects in "highly congested" locations. ORA's workpapers included 26 EBMUD projects, and the criteria used to reduce this list to the seven projects most comparable to PG&E gas pipelines were provided.[497] Project location was not a filter criteria, since data on the level of congestion was not available in the data set ORA obtained. It is correct that ORA excluded two of these seven projects from Table 4C-13 of its testimony, but the table headings clearly indicate that this is because the projects involved a railroad crossing.[498] ORA excluded these projects from Table 4C-13 because of the extra cost to jack up the tracks and support them while boring for the pipeline beneath them is an expensive and atypical step; including these atypical costs for nearly 30% of the projects included, two projects out of seven, overestimates the impact of projects with railroad crossings since only two of all 26 water pipe replacement projects for which ORA obtained data involved a railroad crossing.[499] PG&E's witness did not know the proportion of PSEP or VIPER projects that will cross under railroad tracks,[500] but intuitively the proportion is small, and this is supported by PG&E's PSEP cost forecast.[501]

In hearings, PG&E's witness raised a new reason gas pipelines are more expensive: *"There are public awareness activities that you are not going to see with a water pipe*

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[496] See Ex. ORA-79, Narrative Description of Workpapers, p.19, Table 6 and footnote 33.

[497] All project details are provided in Excel File "WP-ORA-4C-8" included in Ex. ORA-92. Filter criteria and the resulting seven projects are provided in Ex. ORA-79, Narrative Description of Workpapers, p.19, ll. 7-14.

[498] Ex. ORA-34 (Direct Testimony, Corrected Version, Roberts), p.46, footnote 138.

[499] This can be seen by performing a search on "railroad" within the Excel File "WP-ORA-4C-8" included in Ex. ORA-92. In addition, if average unit costs are considered as PG&E has done in its forecast, the impact of these two projects would be very small since they were very short compared to the combined mileage of all projects. The average cost of the five projects in Table 4C-13 of Ex. ORA-34 is $4.22 million/mile which is 3.4% less than the average cost of all seven projects in Table 6 of Ex. ORA-79, which is $4.36 million/mile.

[500] 18 RT 1930-1931 (Barnes/PG&E).

[501] Ex. ORA-85 (PG&E PSEP Prepared Testimony in R.11-02-019, Hogenson), Attachment 3E provides the basis and detailed costs used in PG&E's PSEP cost forecast. This includes additional project specific costs for horizontal directional drilling (HDD) and road bores, but none for boring under railroad tracks. See pages 3E-7 and 3E-15.

replacement. The fact of the matter, there are significantly more safety-related driven activities up to and including those items as well as the items that have to do with ensuring that we have the proper safety practices in place for clearing the area and the maintenance associated with the site."[502] As with PG&E's other claims, these are not supported, and their introduction under cross examination did not allow for follow up discovery.

Customer outreach is also not a difference with a significant impact on overall unit costs. Regarding public awareness activities, in PSEP PG&E forecasted that "customer outreach" would add 2.9% to overall project costs for replacement projects.[503] Regarding additional safety activities, many of the safety activities involved in pipe replacement are independent of the transported media, since in both cases traffic must be controlled, heavy materials must be lifted and moved, welding is involved, and open trenches pose hazards for both workers and others living, working, and commuting near the project site. It seems reasonable that more precautions are required for a flammable gas than for water, but PG&E has provided no evidence of the specific precautions and their cost impact. Even if, hypothetically, the outreach costs for gas pipe replacement were twice as high as for water projects, this would support only that project unit costs for gas pipelines are approximately 1.5% higher.[504] In both cases, significant public outreach is required for these large construction projects that impact customers and neighbors over a long time period, and there is no data to help quantify the cost difference between water and gas pipelines.

ORA has explained why replacement of water pipelines provides a reasonable benchmark for gas pipeline replacement, and provided data for similar size pipelines in the highly populated San Francisco Bay area. PG&E's claims that differences "produce a <u>much</u> lower unit cost for a water main replacement than would be expected for a natural gas pipeline" are not quantitatively

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[502] 18 RT 1919 (Barnes/PG&E).

[503] Ex. ORA-85 (PG&E PSEP Prepared Testimony in R.11-02-019, Hogenson), p.3E-9, § 2.6.5.4.

[504] If water pipeline replacement required half the public outreach cost, this cost would be 2.9%/2 of the total project costs based on PG&E's PSEP forecast, or 1.45%. If the base project costs for water pipelines are similar to those for gas pipelines in the PSEP forecast, as is shown in Table 7.6-5 for large diameter pipes, then the customer outreach costs would be higher by 1.45% of the base project costs for gas pipelines than for water pipelines.

supported.[505] Further, information from discovery and hearings indicates that the differences between water and gas pipe replacement raised by PG&E result in small cost differences relative to overall pipe replacement unit costs. PG&E has not shown that the costs for activities that logically drive the cost of pipe replacement (e.g. the construction costs to safely uncover the old pipe, replace it, and return the job site to its original condition) are different, which would be required to support the significant cost difference shown in Table 7.6-5 above.

In sum, this analysis raises further questions about PG&E's inability to justify the high costs contained in its VIPER forecasts, and provides further support for the reasonableness of ORA's VIPER forecast.

7.7 Geo-Hazard Threat Identification and Mitigation

7.8 Programs to Enhance Integrity Management

ORA does not oppose PG&E's 2015 TY forecast of $1.054 million for root cause analysis or $6.263 million for risk analysis process improvements.[506]

7.9 Valve Automation

7.10 Public Awareness

PG&E is forecasting $4.3 million dollars in expenses to conduct public awareness programs.[507] However, PG&E's forecast for public awareness of $4.344 million is unreasonable and should not be adopted. PG&E began notifying customers living in 2,000 feet of transmission pipeline as a response to a commitment to Congresswoman Speier.[508] PG&E's 2015 TY request represents a 235% increase over 2013 recorded expenses.[509] As with many other programs, PG&E was unable to provide specific breakdowns of program costs and could provide forecasts solely at the total program level.[510]

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[505] Ex. PG&E-39 (Rebuttal Testimony with Errata, Chapter 4A, Barnes), p. 4A-77 (emphasis added).

[506] Ex. ORA-38 (Direct Testimony of Morse with errata), pp. 2-5.

[507] Ex. PG&E-1 (Direct Testimony of Barnes), pp. 4A-63 to 4A-65, and 4A-75 to 4A-77.

[508] Ex. PG&E-1 (Direct Testimony of Barnes), p. 4A-75.

[509] Ex. ORA-38 (Direct Testimony of Morse), p. 6.

[510] Ex. ORA-38 (Direct Testimony of Morse), p. 6.

PG&E's forecast for public awareness is also overly aggressive, reflecting higher than actual labor costs, and over $5 million to meet PG&E's commitment to Congresswoman Speier. For labor costs, PG&E's forecast reflects average labor costs of $309,000 per employee as compared to the actual average labor costs of $176,000 per employee.[511] ORA does not oppose adding an additional employee to support the public awareness program.[512] However, given the high degree of variability in spending, ORA uses a three year average (removing the costs of sending the informational letters PG&E sent after San Bruno) which results in a more reasonable 2015 TY forecast of $2.6 million.[513] This level reflects funding well above pre-San Bruno levels, but excludes the informational letter. PG&E had to commit to this course of action because of their prior imprudent operations. Although there may be benefits to ratepayers, this does not mean in this rate case that it is appropriate for ratepayers to fund them, rather than shareholders.

7.11 **Inoperable and Hard-to-Operate Valves**

ORA recommends capital expenditures of $4.029 million for Inoperable and Hard-to-Operate Valves instead of PG&E's forecast of $7.067 million. Any valve PG&E considers being on the verge of becoming inoperable should be repaired under routine maintenance and not included in this program.[514] While PG&E critiques ORA's averaging method under the guise of an inappropriate selection of years, PG&E's own forecast for 2014 was $3.703 million, which is comparable to ORA's forecast of $4.029 million.[515] Taking the mathematical average of 2009 through 2014, which includes both the old and new definitions results in an average forecast of $3.974 million, still below ORA's recommendation. ORA's forecast therefore is generous, reflects both actual history and even with PG&E's new definition, still is more reasonable than PG&E's forecast which is 75% higher than reasonable based on both past and current progress.

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[511] Ex. ORA-38 (Direct Testimony of Morse), p. 9.

[512] Ex. ORA-38 (Direct Testimony of Morse), p. 9.

[513] Ex. ORA-38 (Direct Testimony of Morse), p. 9.

[514] Ex. ORA-4 (Direct Testimony of Lee), p. 2.

[515] Ex. PG&E-39 (Rebuttal Testimony of Barnes), p. 4A-95.

7.12 **Class Location Program**

Regarding PG&E's Class Location programs, as discussed in PG&E's Rebuttal Testimony, ORA and PG&E not disagree on the mileage to the tested, the escalation rate, the cost of the class location study, or field verification costs.[516] The area where PG&E and ORA disagree is around the unit cost for strength testing and capital expenditures for 2015 for Class Location Programs.[517]

PG&E's 2015 TY forecast costs are driven by two drivers as compared to ORA's forecast. PG&E admits that the forecast in their workpapers, which is double that of their broader hydrotest program, is too high.[518] PG&E has not provided sufficient evidence to demonstrate why this particular program's cost was initially double that of the more routine hydrotest programs. For a broader discussion of hydrotesting, see Section 7.4. In terms of the time periods selected by PG&E, PG&E again cherry-picks data to derive the result it seeks. PG&E bases its use of 2000-2005 data on conjecture of future programs, rather than the more recent data. Furthermore, pipeline maximum allowable operating pressure reductions are one inexpensive alternative which PG&E ignores. According to federal code, so long as the class location change is discovered within the 24 month period and corrective action taken, the operator may lower the pressure and may subsequently raise it again if it follows the proper procedures.[519] While PG&E discusses 3.8 miles a year needing mitigation, it does not discuss the operating pressure versus the maximum allowable operating pressure, which is the critical decision path that should determine whether a pipeline a) has the maximum allowable operating pressure lowered but with no impact on actual operating pressures; b) needs to be pressure tested, because it had not previously been pressure tested for 8 hours or more in duration; or c) needs to be replaced. Additionally, given the extensive program of pressure testing PG&E has been conducting to bring it system back in compliance through the PSEP program, there should be a limited subset of miles that have not been pressure tested for an 8 hour period of time.

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[516] Ex. PG&E-39 (Rebuttal Testimony of Mojica), p. 4B-4.

[517] Ex. ORA-39 (Direct Testimony of Logan), p. 2.

[518] Ex. PG&E-39 (Rebuttal Testimony of Mojica), p. 4B-6.

[519] 49 Code of Federal Regulations § 192.611 (Change in class location: Confirmation or revision of maximum allowable operating pressure).

For these reasons, PG&E's forecast is unreasonable, and ORA's recommendations should be adopted.

7.13 Water and Levee Crossing Program

7.14 Shallow Pipe Program

7.15 Gas Gathering Program

7.16 Work Required by Others Program

8 STORAGE

8.1 Overview and Summary

8.2 Stipulation Between PG&E and ORA

ORA supports the stipulation between PG&E and ORA, Ex. Joint Stipulation-3. ORA did not oppose PG&E's forecasts for storage, which results in 2015 TY expenses of $638 thousand and capital expenditures of $12,456 thousand.

8.3 Comments

9 FACILITIES

9.1 Overview and Summary

9.1.1 Stipulation Between PG&E and ORA

After the hearings were completed, PG&E and ORA entered into a stipulation[520] of the issues discussed in Ex. ORA-11, ORA's testimony on Asset Families – Facilities.

ORA and PG&E had significant disagreements regarding Engineering Critical Assessment (ECA) Phase I and II and Hydrostatic Testing,. ORA recommended that PG&E receive no funding for these programs and that PG&E should be directed to file an advice letter or application to establish a memorandum account once PHMSA establishes new Integrity Verification Process rules.[521] In contrast, PG&E forecast a total of over $30 million for these

[520] Ex. Joint-6.

[521] Ex. ORA-11 (Lee/ORA), pp. 4-6.

programs in 2015.[522] In reaching their joint stipulation, ORA and PG&E both agree that PG&E is proposing moving forward on these programs in advance of a PHMSA rulemaking and that there is little industry experience.[523] ORA and PG&E have agreed to a hybrid of their two recommendations. PG&E would receive one half of the funding for ECA Phase I and II and Hydrostatic testing up front, and the remainder of the adopted forecast would be authorized through this decision to be collected once new regulations go into effect.[524] This approach provides reasonable safeguards to ratepayers if new regulations are not adopted while allowing a slower pace of work where there is great uncertainty over costs.[525]

9.2 ECA Phase 1

9.3 ECA Phase 2

9.4 Hydrostatic Station Testing

9.5 Critical Documents

ORA recommends zero funding for critical documents since this program should have been conducted by PG&E as part of the safe operations of its system.[526] PG&E has forecast $11.573 million to address this. PG&E's justification is that station documentation packages and information vary widely between sources.[527] PG&E's argument is reminiscent of its justification for the Pipeline Records Integration Program, and similarly should be rejected. As the Commission found in D.12-12-030:[528]

> "PG&E became responsible for its natural gas transmission system the day it installed facilities and equipment for the system. That responsibility includes creating and maintaining records of the location and enegineering details of system components."

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[522] Ex. Joint -6 (PG&E-ORA), p. 1.

[523] Ex. Joint -6 (PG&E-ORA), p. 1.

[524] Ex. Joint -6 (PG&E-ORA), p. 2.

[525] For example, *see generally* 25 RT 3305 – 3306.

[526] Ex. ORA-11 (Lee/ORA), pp. 6-8.

[527] Ex. PG&E-39 (White/PG&E), pp. 6-11 – 6-13.

[528] D.12-12-030, p. 87.

PG&E argues that their lack of updating, standardizing, and maintaining critical documents for their facilities is a new program that ratepayers should fund. However, this requirement is longstanding and PG&E's request for ratepayer funding should be denied.

9.6 Data Acquisition and Metric Development

9.7 Physical Security

9.8 Becker System Upgrades

9.9 Gas Quality Practice Assessment

9.10 Gill Ranch O&M

9.11 Routine Expense

9.12 Burney K-2 Compressor Replacement

9.13 Los Medanos K-1 Compressor Replacement

9.14 Compressor Unit Control Replacements

9.15 Upgrade Station Controls

9.16 Emergency Shutdown System Upgrades

9.17 Rebuild Santa Rosa Compressor Station Electrical Substation

9.18 Upgrade Pleasant Creek Processing Facilities

9.19 Gas Transmission Electrical Upgrades-Hinkley and Topock Compressor Stations

9.20 Gas Transmission Electrical Upgrades-Compressor Stations (excludes Hinkley, Topock, Santa Rosa)

9.21 Physical Security

9.22 Hinkley Compressor Unit Retrofit Project

ORA opposes the capital expenditures request to retrofit an additional compressor unit at Hinkley during this 2015 to 2017 GT&S period. PG&E provides no clear evidence that an additional retrofitted unit is required for reliability. In a data response to ORA, PG&E provided the actual yearly service hours of each compressor from 2009 to 2013.[529] For the compressors (K-1, -3, -4, -7, -10, -11, and -12) that are permitted to operate 24 hours a day for 365 days a years (8,760 hours), none of the units came close to the 8,760 hours. Forthe compressors (K-2, -5, -6, -8, -9) that are limited to 1,500 hours per year, none came close to the limit each year. The evidence provided by PG&E clearly shows that the current mixed of compressors are providing reliable service, therefore no funding should be provide to retrofit an additional unit.

9.23 Install Active Fire Suppression Systems

9.24 Perform Simple Station Rebuilds

9.25 Perform Complex Station Rebuilds

9.26 Perform Transmission Terminal Upgrades

9.27 SCADA Visibility

9.28 Replace Obsolete Bristol Controllers

9.29 Replace Obsolete Limitorque Valve Actuators

9.30 Electrical Upgrades Program

9.31 Biomethane Interconnects

PG&E's request for $4.815 million for biomethane interconnects should be denied. As ORA explained in testimony, the tariffs require the supplier to pay for interconnects.[530] The proposed change to Rule 21 retains the same language and PG&E's opening comments in that application stated that PG&E would remove those costs.[531] Given that the party seeking the interconnection should pay costs, it is not reasonable for ratepayers to pay for these costs.

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[529] Ex. ORA-68 (Lee/ORA), p. 13. ORA DR-47 Q3 (Compressor operating hours).

[530] Ex. ORA-11 (Lee/ORA), p. 11.

[531] PG&E Opening Comments in Phase 2 of R.13-02-008.

9.32 **Routine Capital Spending**

10 CORROSION CONTROL

10.1 Overview and Summary

PG&E is forecasting $98,982 million[532] in expenses and $49 million in capital expenditures[533] for inclusion in the 2015 revenue requirement and rate base "to execute a comprehensive corrosion control program across the gas transmission asset families."[534] PG&E's 2011 and 2012 recorded expenses were only $2.844 million and $8.450 million respectively, [535] and 2011 and 2012 recorded capital expenditures were $5.872 million and $8.194 million.[536] For 2013 and 2014, PG&E forecasted $13.436 million and $17.839 million in expenses[537] and $3.352 million and $15.754 million in capital expenditures.[538] PG&E claims that "PG&E started the overhaul of its approach to corrosion control in 2012, as evidenced by the actual and forecast expenditures from 2012-2014."[539]

Prior to this rate case cycle, PG&E did not previously even have a formal corrosion control program, instead performing aspects of corrosion control work as a part of various other pipeline maintenance activities.[540] PG&E testified that it "experienced a number of regulatory audit findings and self-reported non-compliance issues related to its corrosion control program"[541] and that "[a]s reflected in the previous audit findings and self-reported non-compliances, PG&E has inadequately focused on certain aspects of corrosion control in the past. PG&E is not requesting recovery of the costs to address those deficiencies arising from past

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[532] Ex. PG&E-1, p. 7-3, Table 7-1 (Armato/PG&E) ; *see* 21 RT 2463:5-20.

[533] Ex. PG&E-1, p. 7-2. (Armato/PG&E).

[534] Ex. PG&E-1, p. 7-1. (Armato/PG&E)

[535] Ex. PG&E- 1, p. 7-3, Table 7-1(Armato/PG&E); RT

[536] Ex. PG&E-1, p. 7-4, Table 7-2. (Armato/PG&E)

[537] Ex. PG&E-1, p. 7-3, Table 7-1. (Armato/PG&E)

[538] Ex. PG&E-1, p. 7-4, Table 7-2. (Armato/PG&E)

[539] Ex. PG&E-1, p. 7-5. (Armato/PG&E)

[540] Ex. PG&E-1, p. 7-5. (Armato/PG&E); Ex. ORA-40, p. 4 (Karle/ORA).

[541] Ex. PG&E-1, p. 7-5 (Armato/PG&E).

practices."[542] PG&E claims it will incur $58 million in 2015 – 2017 expense and $21 million in 2015- 2017 capital expenditures "to bring its program into compliance"[543] and is not requesting recovery of such costs from ratepayers in this proceeding on this basis. However, PG&E provided no workpapers to support the specific expense and capital expenditure amounts it claims to exclude from the application to address admitted deficiencies for past practices, on the basis that they were not "forecasting them here in this rate case."[544] PG&E argues "the 4-year mitigation pace is appropriate to address the risk because contacted casings could be experiencing unmitigated active external corrosion which compromises transmission pipeline integrity." [545] PG&E also justifies its increased focus on addressing corrosion in this rate case cycle as reflective of a new industry perception of increased risks of corrosion, stemming from incidents that occurred in 2007 and 2009.[546]

ORA agrees with PG&E that its corrosion control program has been deficient, and requires increased funding, with a portion to be borne by PG&E shareholders to reflect PG&E's past deficiencies, but that the shareholder portion should be far larger to reflect such deficiencies and the deficiencies defined differently than PG&E proposes. ORA testified that "much of PG&E's capital and expense forecast appears to consist of deferred maintenance to be performed in order to bring PG&E's gas transmission facilities into compliance with longstanding federal regulations. Where this is the case, ORA recommends appropriate cost caps for ratepayers in order to ensure that shareholders bear some level of responsibility for costs associated with PG&E's deferral of necessary pipeline maintenance."[547] ORA did increase the ratepayer proportion of these costs in its forecast by approximately 50% above 2013 levels to account for

[542] Ex. PG&E-1, p. 7-6 (Armato/PG&E).

[543] Ex. PG&E-1, p. 7-6 (Armato/PG&E) ($58 million in expense and $21 million in capital for the 2015-2017 period).; 21 RT 2457:5 -16 (Armato/PG&E); 22 RT 2563:24 – 2564:13 (Armato/PG&E).

[544] 22 RT 2564:16-24 (Armato/PG&E) (explaining that "[w]e don't have workpapers for the excluded amounts," and when asked why not, "Because we are not forecasting them here in this rate case.")

[545] Ex. PG&E-1, p. 7-36 (Armato/PG&E).

[546] Ex. PG&E-40, pp. 7-35 to 7-36 (Armato/PG&E); 22 RT 2507:18 – 2508:17 (Armato/PG&E) .

[547] Ex. ORA-40 (Karle/ORA), p. 1.

increased rates of finding and mitigating casings, so the burden is not borne entirely by shareholders.[548]

The largest portion of PG&E's increased forecast for corrosion control relates to the Company's proposed program to "mitigate" an almost decade-old inventory of pipelines with contacted casings and hence a definitive increased risk for corrosion by extensively redesigning and modernizing the casings surrounding such pipelines through excavation, rather than eliminating the source of the contact in the current casing or minimizing the corrosion caused by such a contact without extensive excavation. Since 2004, PG&E has developed a backlog of 335 unmitigated contacted casings, which PG&E now proposes to remediate over a four-year period that includes the entire period of the application any beyond into 2018, and fully funded by ratepayers despite multiple audits over a period of years warning PG&E of its lack of compliance with applicable regulations. PG&E concedes its so-called "corrective action" plan previously only specifically focused on mitigating a subset of contacted casings, "metallic" contacted casings, and did not address the unmitigated casings proposed in the current rate proceeding, [but should still qualify as a corrective plan for these contacted casings which are being proposed to be mitigated in this proceeding]. Even where PG&E did conduct corrective actions, PG&E's own internal audit reports indicate that 19% of the inspections made were not done by operator qualified personnel as required under 49 C.F.R 192 § 453.[549, 550] ORA's recommendations regarding this program are:

- A 2015 cost cap of $4,895,618 for expense mitigation of contacted casings, because this work appears to be deferred maintenance intended to meet longstanding federal regulations. PG&E has forecast $48,503,848 for expense mitigation of contacted casings in 2015. ORA's proposed cost cap is equal to PG&E's 2013 spending on expense casing mitigation with additional funding for the six additional expense casings PG&E expects to find and mitigate in 2015.

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548 Ex. ORA-40 (Karle/ORA), pp. 10-11.

549 22 RT 2518:1-24 (Armato/PG&E).

550 49 CFR 192 § 453 states: "The corrosion control procedures required by §192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods."

- A 2015 cost cap of $1,935,137 on capital expenditures for mitigation of contacted casings, which is equal to PG&E's 2013 capital expenditure on casing mitigation with additional funding for the 1.33 additional capitalized casings PG&E expects to find and mitigate in 2015. PG&E has requested recovery for $21,083,693 in 2015 capital expenditures.[551]

ORA's recommendations regarding the remainder of PG&E's 2015 corrosion control expense forecasts are:

- $2,024,231 for 2015 Direct Current (DC) interference mitigation which accounts for investigation and half of PG&E's mitigation forecast, and which excludes $527,638 of PG&E's $2,551,869 expense forecast for DC interference mitigation.
- $16,143,948 in 2015 expenses for atmospheric corrosion, which accounts for investigation and half of PG&E's mitigation forecast, and which excludes $4,293,098 of PG&E's $20,437,046 forecast.[552]
- ORA revises its recommendation in opening testimony regarding PG&E's 2015 forecast of expenses for AC interference from $527,500 to $0, based on PG&E's lack of workpapers.[553, 554]

ORA's recommendations regarding the remainder of PG&E's 2015 corrosion capital expenditure forecasts are:

- $5,750,555 in capital expenditures for 2015 Alternating Current (AC) interference mitigation, which accounts for investigation and half of PG&E's mitigation forecast, and which excludes $4,599,177 from PG&E's $10,349,647 capital expenditure forecast.
- $400,893 in capital expenditure forecast for 2015 DC interference mitigation, which accounts for half of PG&E's mitigation forecast of $801,786 and excludes $400,893 of PG&E's forecast.[555]

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[551] Ex. ORA-40 (Karle/ORA), p. 1; *see also id.,* Table 7-1, p. 2.

[552] Ex. ORA-40 (Karle/ORA), p. 1; *see also id.,* Table 7-1, p. 2.

[553] *See* Ex. ORA-40 (Karle/ORA), pp. 12, 14.

[554] 22 RT 2541:24 – 2543:14. PG&E did not provide workpapers for programs with costs less than $1 million, despite ORA's requests during discovery.

[555] Ex. ORA-40 (Karle/ORA), p. 2; *see also id.,* Table 7-2, p. 3. ORA reiterates "that the lack of a specific ORA disallowance or forecast in some program areas should not be taken to constitute agreement with PG&E's proposals." Ex. ORA-40 (Karle/ORA), p. 2. ORA argues that PG&E is responsible for ensuring the safety of its system and compliance with applicable safety regulations independent of the specific level of revenue requirement the Commission adopts in this proceeding.

10.2 **Casings**

10.2.1 Contacted Casings and Corrosion Control

As PG&E testified:

> When pipelines were installed under roads, railroads or canals, a prior practice was to place casing around the pipe for protection and convenience, in the event the pipe needed replacement. However, casing installations have been phased out since the pipe cannot be externally inspected when it is housed in a casing, and the casing and pipe can come in contact with one another causing corrosion concerns at or near the point of contact. Casings require both annual routine monitoring and mitigation as appropriate.[556]

Although casings are no longer a feature of new pipeline installations, because a substantial amount of pipelines are housed in casings, and the corrosion problems are not always associated with pipelines in casings, PHMSA enacted specific regulations in the 1970's governing inspections of pipelines enclosed in casings, detection of whether such casings contact pipelines, and detection of any subsequent corrosion resulting from such contacts.[557] Short of fully replacing a pipeline in a casing with one without a casing, a utility can mitigate, or substantially lessen the possibility of a pipeline in a casing being contacted by the casing and the subsequent risk of corrosion, by excavating and modernizing the casing itself to avoid such contacts in the first place, as PG&E is now proposing with the 335 contacted casings they describe as "unmitigated" contacted casings, thereby isolating the casing from the carrier pipe. A utility can also take measures to mitigate the likelihood of contacts in pipelines even in existing casings, and can take measures to minimize the corrosion resulting from such contacts, in lieu of a more full mitigation represented by PG&E's proposal in this proceeding, to the extent such measures actually succeed in minimizing the occurrences of contacts and impacts of resulting corrosion.

PG&E further explains there are two types of contacts between casings and "the carrier pipe" transporting the natural gas: "metallic" or "hard" contacts that "develop mainly as a result

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[556] Ex. PG&E-1, p. 7-35 (Armato/PG&E); *see also* Ex. ORA-40, pp. 4-5 and fn. 4, *citing* Ex. PG&E-1, p. 7-35 and *also* 22 RT 2750 and Ex. PG&E-63.

[557] 22 RT 2511:19-24 (Armato/PG&E). ("One of the issues with casings is you can't tell when there is a contact on the casing, what the cathodic protection level is of the pipe inside of that casing. So it may be okay or it may not be.")

of differential settlement between the casing and the carrier pipe";[558] and "electrolytic" contacts that "can develop when liquids (such as water) enter the casing through an end seal failure or leaks in the casing."[559] PG&E noted that, "[h]istorically, as PG&E identified contacted casings through annual testing a corrective action plan was created and casing mitigation was focused primarily on metallic contacts."[560]

10.2.2 PG&E's Proposal To Mitigate 335 Currently Contacted Casings Over Four Years Through Excavations of and Repairs to the Casings

PG&E's proposal in this proceeding is to address 335 casings it has identified through its casing monitoring program, integrity management program, and testing program for electrical isolation "as contacted and in need of mitigation"[561] though its proposal to mitigate the contacted casings. The mitigation proposal itself generally consists of:

> excavation to expose the ends of the casing, examination of all possible sources for contacts including the end seals, alignments, casing dents, EST, etc., and then taking appropriate corrective action. Corrective action may include: replacing end seals; removing segments of the casing; replacing link seals and insulation spacers, flushing, and draining casings; repairing pipeline coatings, and gelling the casing after site restoration. A typical casing mitigation project averages from 10 days to a month.[562]

In other words, PG&E is proposing to take increased actions to ensure that the casings will no longer contact the carrier pipe, as these casings have been and still are contacted in multiple locations for many years.

PG&E had not just recently discovered the 335 contacted casings included in the mitigation plan at the time the application was filed in December, 2013, but had known of numerous contacted casings dating as far back as 2005 that had never since been

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[558] Ex. PG&E-1, pp. 7- 35 to 7-36 (Armato/PG&E).

[559] Ex. PG&E-1, p. 7-36 (Armato/PG&E).

[560] Ex. PG&E-1, p. 7-36 (Armato/PG&E)

[561] Ex. PG&E-1, p. 7-36 (Armato/PG&E).

[562] Ex. PG&E-1, p. 7-37 (Armato/PG&E).

mitigated.[563] During this same time period PG&E was mitigating far fewer contacted casings each year than it was discovering each year and developing a growing backlog of contacted casings that have remained unmitigated until PG&E's current plan is implemented.[564]

10.2.3 Applicable Regulations

Volume 49 of the Federal Code of Regulations §192.467 (a) requires that pipelines be electrically isolated:

Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.[565]

A subsequent subsection, §192.467 (c) mandates that a pipeline in electrical contact with its casing requires mitigation, either through isolation, or measures to minimize the corrosion in the pipeline itself:

Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.[566]

The regulatory requirements of §192.467(c) were adopted in 1968 and have not been amended since 1978. In order to interpret these subsections, PHMSA issues interpretations[567], with a focus on how to determine whether "other measures must be taken to minimize corrosion" other than isolation. One such PHMSA Interpretation, #PI-86-004 dated July 24, 1986 states the following regarding violations of Paragraph 192.467 (c) above:

> A violation of Paragraph 192.467(c) exists if: A cathodically protected transmission or distribution pipeline, other than unprotected copper inserted into ferrous pipe, is electrically connected to metallic casings that are a part of the underground system and within six months of discovery of the electrical short

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[563] 22 RT 2502:27 – 2505:4 (Armato/PG&E); ORA-138 (PG&E Response to ORA 130 Question 1, Attachments 1 and 2)

[564] 22 RT 2505 generally (Armato/PG&E); *Cf.* ORA-138 (PG&E Response to ORA 130 Question 1, Attachments 1 and 2), PG&E-40, p. 7-43.

[565] 49 C.F.R.§192.467(a) (2013).

[566] 49 C.F.R.§192.467(c) (2013).

[567] While these interpretations are not legally binding, per 192 C.F.R. 13(c) operators must adopt mandatory plans to address corrosion and follow such plans, and PHMSA interpretations are often adopted as part as such plans.

> between the casing and pipeline, the operator has not initiated corrective action in accordance with Paragraph 3 below.
>
> 3. Reasonable time allowance and method for operator's correction of shorted casings:
> A. After the cathodic protection survey has been completed and a shorted casing has been identified, the operator should determine a course of action intended to correct or negate the adverse effects of shorted casings. The operator's plan of action should be initiated within six months of completion of the survey and should include one of the following options:
> i). Clear the short if practical;
> ii). Fill the casing/pipe interstice with high dielectric casing filler or other material which provides a corrosion inhibiting environment.
> iii). If options i or ii would be impracticable and, if in the judgement of the operator the risk of corrosion is minimized by conditions including the location and condition of the pipe, the risk of overpressure, and environmental factors, the operator may choose to monitor the casing with leak detection instruments at intervals not exceeding the requirements of 192.705 and 192.721 until such time as options i or ii become practicable or conditions change which render option iii inadequate to minimize the risk of corrosion. If the operator chooses to monitor the shorted casing with leak detection instruments, immediate corrective action must be taken if and when a leak is discovered. A corrosion leak is a condition that would render option iii inadequate.[568]

PG&E notes that it follows a similar PHMSA interpretation based on a 1987 revision of the 1981 Corrosion Enforcement Guidelines upon which #PI-86-004 was based,[569] from 1987, #PI-94-022.[570] These guidelines stated that a violation exists if a contacted casing exists and "the operator has not taken corrective action within six months of discovery to initiate plans for correction of the short."[571] It notes the operator must be investigated to determine it has a "written procedure to react to shorted casings" and "follows the written procedure."[572] The plan later states:

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[568] Ex. ORA-69 (Karle/ORA, Attachments to ORA-40), Attachment 2, PHMSA Interpretation #PI-86-004, July 24, 1986, pp, 2, 4 of Attachment 2.

[569] PG&E-40, pp. 7-39 to 7-40 (Armato/PG&E)

[570] PG&E-40, Chapter 7, Attachment D (Armato/PG&E).

[571] PG&E-40, Chapter 7, Attachment D, p. 7-AtchD-1, Section 1.

[572] PG&E-40, Chapter 7, Attachment D, p. 7-AtchD-1, Section 1.

Reasonable time allowance and method for operator's correction of shorted casings:

a. After the cathodic protection survey has been completed and a shorted casing has been identified, the operator should have determined a course of action intended to correct or negate the adverse effects of shorted casings. The operator's plan of action should be initiated within six months of completion of the survey and should include one of the following options or an equivalent option developed by the operator.

i. Clear the short, if practical;
ii. Fill the casing/pipe interstice with high dielectric casing filler or other material which provides a corrosion inhibiting environment;
iii. If options (i) or (ii) would be impractical and, if in the judgment of the operator the risk of corrosion is minimized by conditions including the location and condition of the pipe, the risk of overpressure, and environmental factors, the operator may choose to monitor the casing with leak detection instruments at intervals not exceeding 7 1/2 months, but at least twice each calendar year until such time as options (i) or (ii) become practical or conditions [change] which render option (iii) inadequate to minimize the risk of corrosion. If the operator chooses to monitor the shorted casing with leak detection instruments, immediate corrective action must be taken if and when a leak is discovered. A corrosion leak is a condition that would render option (iii) inadequate.[573]

PHMSA's current guidelines state:

1. A cathodically protected transmission, distribution gas pipeline and hazardous liquid pipeline is electrically connected to metallic casings that are a part of the underground system, and within six months of discovery of the electrical short between the casings and pipeline, the operator has not initiated corrective action.
The operator's procedures should also be investigated to:
a. Determine that the operator has a written procedure to react to a shorted casing.
b. Determine that the operator follows the written procedure.
c. Metallic short is discovered between pipeline and casing and the operator did not take any remedial action.
d. Determine that the operator performs annual testing of casings for shorted conditions.[574]

The common threads are that an operator who discovers a contacted pipe must, within six months, start of plan of action that, if isolating the pipeline is not achieved because of impracticality under 49 C.F.R., must clear the contact, or minimize the possibility of contact; or if these two possibilities are also impractical, continue monitoring until clearing the contact or

[573] PG&E-40, Chapter 7, Attachment D, pp. 7-AtchD-2 to 7-AtchD-3, Section 3. ORA believes the word "change" was unintentionally omitted in these guidelines.

[574] Ex. ORA-137 (PHMSA Part 192 Corrosion Enforcement Guidance, August 2013), p. 72.

minimizing the possibility of the contact is practical, or corrosion or a leak actually is detected, or "conditions change to render option iii" – monitoring – "inadequate to minimize the risk of corrosion."

In other words, PG&E is claiming that its prior corrosion monitoring program used to satisfactorily monitor the risk of corrosion and meet the conditions of such programs, when it was rarely mitigating contacts but only monitoring such contacts, but as of now conditions have changed such that monitoring programs no longer are adequate and isolation of the contacts is required.

10.2.4 PG&E Interprets the Regulations as Having Permitted PG&E's Failure to Mitigate Contacted Casings For Years But Now Requiring Immediate Mitigation Through Isolation to Eliminate the Backlog of Casings, But Fails To Show Its Plans To Monitor Pipelines To Minimize Corrosion Were Adequate

In order to justify its current request for a comprehensive mitigation proposal as a reasonable method to remediate contacted casings, PG&E must show that it is necessary to mitigate contacted casings now to satisfy the requirements of the statute, but was not required when PG&E failed to mitigate such casings through isolation or other methods over the past decade and instead it monitored the risks associated with the corrosion associated with contacted casings properly in the past, and that changed conditions justify isolating the contact now instead. But numerous aspects of its plans were inadequate, as explained below.

10.2.4.1 PG&E Lacks Required Records That Could Show It Initiated Corrective Action Plans Within Six Months

PG&E cannot show it met the requirement that they initiated a plan of corrective action within six months of discovering a contacted casing, as it lacks records of when they initiate a plan of corrective action for each contact. Although PG&E noted it followed #PI-94-022 set forth above which requires the initiation of a corrective action plan within six months,[575] PG&E stated "[b]ecause the applicable regulations do not specify a time frame within which corrective

[575] PG&E also noted that "prior to November 2008, PG&E GT&S Standard S4126: 'Cathodic Protection Standards for Cased Pipeline Crossings' (implemented in December 1998) was in effect and required initiation of corrective plans within six months. Ex. PG&E-40 (Armato/PG&E), pp. 7-38 – 7-39; Ex. PG&E-40, p, 7-AtchC-3.

action, or corrective action plans, must be initiated, PG&E does not have a practice of tracking the date when PG&E initiates a corrective action plan."[576] 49 C.F.R § 192.491 requires that operators maintain records to demonstrate the adequacy of corrosion control measures or that a corrosion condition does not exist.[577] Without data about when it starts its corrective action plans, PG&E cannot guarantee it meets the requirements that allow a corrective action plan to suffice instead of more stringent measures. ORA disagrees that there has not been a requirement to initiate a corrective action plan within six months of discovering a contacted casing. Nonetheless, PG&E still maintains that it follows a work procedure,WP 4133-04,[578] dated November, 2008, which governs its corrective action plans, and that "that corrective action plan is initiated within six months of identifying a potentially contacted casing"[579] without any further factual support for that statement. PG&E fails to meet its burden of showing that it met the most elemental requirement of monitoring contacted casings rather than taking more stringent measures if it cannot show it initated such plans within six months of discovering a contacted casings.

10.2.4.2 PG&E's Monitoring of Corrosion on Contacted Casings Has Never Been Sufficiently Accurate

The purpose of allowing the monitoring as an exception to the requirement to isolate contacted casings, or minimize the likelihood of contacts or any resulting corrosion. If monitoring cannot accurately find out the conditions of the casing and carrier pipe, it fails its basic mission. PG&E witness Armato admits that determining the level of cathodic protection in a carrier pipe in a contacted casing is not possible. [580] If so, PG&E had been failing for years to

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[576] Ex. ORA-138 (ORA DR 130 Q1, and Attachments 1 and 2), pp. 1-2.

[577] 49 C.F.R. § 192.491 (2013).

[578] Ex. PG&E-44 (PG&E Rebuttal Appendix A/Armato), pp. A-154 to A-159; 22 RT 2506:26 – 2507:14 (Armato/PG&E).

[579] Ex. ORA-138 (ORA DR 130 Q1, and Attachments 1 and 2), p. 2.

[580] 22 RT 2511:19-24 (Armato/PG&E). ("One of the issues with casings is you can't tell when there is a contact on the casing, what the cathodic protection level is of the pipe inside of that casing. So it may be okay or it may not be.")

sufficiently monitor the level of corrosion as an alternative to more stringent measures such as isolation.

10.2.4.3 PG&E Justifies Its Current Mitigation on Increased Risk, When Its Risk Assessment Model Notes That Corrosion Risk Increases Over Time

PG&E explains that PG&E's own independent evaluation of the risk of such contacted casings was too low, and that it now views that risk as higher in its Risk Assessment Model and thus plans to mitigate the contacted casings rather than monitor the casings for corrosion.[581] However, that risk model views corrosion as a time-dependent threat[582]– which PG&E notes means "the threat level may grow if unchecked."[583] PG&E witness admitted he that the corrosion issues "maybe or maybe not"[584] would have been smaller had the casings been remediated earlier, because they cannot determine the level of cathodic protection. Because PG&E had previously underestimated the risk of corrosion – even if that was an industry-wide failure – and that risk could have grown over time to justify its current mitigation proposal, its inaction contributed to the greater amount of mitigation now. PG&E concedes that "[h]istorically, as PG&E identified contacted casings through annual testing a corrective action plan was created and casing mitigation was focused primarily on metallic contacts."[585]

10.2.4.4 PG&E Failed to Monitor All Locations, At Least Until Initiation of WP 4133-04

An August, 2010 Internal PG&E Audit noted that PG&E local office lacked records of maintenance or corrective action at numerous casing locations that lacked test stations ,and that WP4133-04 initiated in November, 2008, had protocols for wireless monitoring and replaced an earlier work procedure, GT&S Standard S4126.[586] PG&E noted this new procedure for wireless

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[581] Ex.PG&E-40, p. 7-35 (Armato/PG&E).

[582] Ex. PG&E-1, Figure 2-2, p. 2-20 (PG&E/Soto). PG&E Witness Armato agreed with this description. 22 RT 2509:25 – 2510-25 (PG&E/Armato).

[583] Ex. PG&E-1, Figure 2-2, p. 2-20 (PG&E/Soto)

[584] 22 RT 2511:13-19 (PG&E/Armato).

[585] Ex. PG&E-1, p. 7-36.

[586] Ex. TURN-14 (Attachment 5 to PG&E's Response to TURN data request 10-5), NCR05 p. 1 of 2,

montitoring in disputing this audit finding,[587] but not that prior to WP4133-04 the previous work procedure lacked such protocols. Failing to monitor all locations up until that time was a violation.

10.2.5 ORA's Proposed Expense and Capital Expenditure Levels for Casings Is Reasonable

In order to reflect the deferred maintenance in mitigating casings that has led to PG&E's proposal to reduce its backlog of contacted casings through mitigation of 335 contacted casings over four years, ORA has recommended a 2015 expense casings forecast which takes 2013 PG&E casings spending as its starting point:

> ORA's recommendation for expense was developed by applying the utility's ratio of expense to capital projects of three to one[588] to the total number of casing mitigations performed in 2013. As there were 9 casing mitigations performed in 2013, using PG&E's three to one ratio, 6.75 of those mitigations would have been expense. ORA then added 6 additional mitigations, to account for PG&E's projection for additional expensed contacted casings to be identified on a yearly basis. Thus ORA's recommendation fully funds future compliance with federal regulations, while disallowing ratepayer funding over what PG&E spent in 2013 for the portion of its request representing deferred maintenance.

…. this approach resulted in a forecast of 12.75 expense casing mitigations per year, which, multiplied by PG&E's forecast unit cost ($383,970), resulted in a total of $4,895,618.[589]

ORA's recommended 2015 capital expense casings forecast also takes 2013 capital projects as its starting point:

ORA's recommendation for capital expenditures was developed in the same manner as ORA's recommendation for expense: by applying the utility's ratio of expense to capital projects (three to one) to the total number of casing mitigations performed in 2013. As there were 9 casing mitigations performed in 2013, 2.25 of those would represent capitalized mitigations.

[p.116 on the .pdf version]; *see* 22 RT 2512:6 – 2516:9 (Armato/PG&E).

587 22 RT 2512:6 – 2516:9 (Armato/PG&E).

588 PG&E-1, p. 7-37 (Armato/PG&E).

589 ORA-40, pp. 10-11. (Karle/ORA).

ORA then added 1.33 additional mitigations to account for PG&E's projection of four additional capitalized contacted casings to be identified over the three year rate cycle. This resulted in a forecast of 3.58 capitalized casing mitigations per year, which multiplied by PG&E's forecast unit cost ($540,451) results in a total of $1,935,137.[590]

ORA's choice of 2013 actual figures was reasonable because it was the most recent cost data available, in a year by which PG&E had already started its overhauled approach to corrosion control as evidenced by the level of actual forecast costs in 2012-2014.[591] Thus, PG&E already believes 2013 costs reflect an increased emphasis on casings.

ORA maintains that the level of casings reflects some level of deferred maintenance, by a straightforward definition that places PG&E responsible for complying with applicable safety regulations, including the PHMSA rules on casings, and the Public Utilities Code Section 451 requirements that PG&E maintain a safe and reliable transmission system. PG&E has always been responsible for mitigating the impacts of contacted casings, and acknowledges that it requested money in Gas Accord V for casings.[592] PG&E's primary policy witness noted:

> Q: What if PG&E should have forecasted the maintenance work in a previous application but did not? Isn't PG&E responsible for forecasting all appropriate safety maintenance work that is required?
>
> A Yes.
>
> Q Okay. And regardless of whether PG&E forecasted a specific maintenance activity that turns out to be necessary, PG&E is responsible for performing such maintenance. Isn't that correct?
> A Yes. That is correct. That changes over time.[593]

ORA's recommended level for 2015 casings spending is based on this principle, that PG&E had the responsibility to address its problems with contacted casings earlier, and thus had a smaller problem with lower costs for ratepayers in 2015. Given PG&E's failings to mitigate casings and comply with the guidelines that allow PG&E only to monitor casings ifthey properly follow

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[590] Ex. ORA-40, p. 11 (Karle/ORA).

[591] Ex. PG&E-1, p. 7-5. (Armato/PG&E) ("PG&E started the overhaul of its approach to corrosion control in 2012, as evidenced by the actual and forecast expenditures from 2012-2014.")

[592] Ex. PG&E-40, p. 7-12.

[593] 12 RT 802:18 – 803:16 (PG&E/Stavropoulos).

requirements for such monitoring and until such time when montitoring is ineffective, which was long before PG&E ramped up its spending forecasts considerably in this proceeding. PG&E shareholders should bear these excessive costs associated with PG&E's dilatory behavior.

10.3 **AC Interference**

Stray Alternating Current (AC) along a gas pipeline can cause or accelerate external pipeline corrosion. PG&E states in testimony that the Company is in the process of formalizing an AC mitigation program, and that "in the past, PG&E addressed AC interference issues on an as needed basis."[594]

PG&E is forecasting $527,500 in AC interference expense in 2015. The Company is forecasting $10.3 million in capital expenditures for 2015, $16.5 million for 2016, and $15 million in 2017. The extent to which the forecast consists of incremental spending is unclear, given PG&E's 2012 redesign of major work categories.[595] PG&E claims that it "has not previously asked for specific AC interference program funding in prior rate cases, however, this program work has been performed in an *ad hoc* manner." [596] PG&E reports having completed only one AC interference mitigation project in the period between 2005 and 2012, at a cost of $362,424 for AC mitigation along 0.6 miles of transmission pipe.[597]

Federal regulations require that gas pipeline operators monitor for and mitigate stray currents. Volume 49, Code of Federal Regulations §192.473 states that:

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.[598]

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[594] PG&E-1, p.7-28 (Armato/PG&E).

[595] PG&E-1, p.7-15 (Armato/PG&E).

[596] PG&E-1, p. 7-32 (Armato/PG&E).

[597] Ex. 69 PG&E Response to TURN-DR-14 Q6.

[598] 49 CFR § 192.473 (2013).

This section originated in 1968, and was last amended in 1978. PHMSA enforcement guidance lists two examples of probable violations of § 192.437(a); if "the operator does not have a written program to minimize the detrimental effects of stray currents," or "if there are potential sources of interference, the operator did not perform testing or take mitigative actions in accordance with its program, as necessary."[599]

While PG&E is currently formalizing an AC interference mitigation program, the company has not been performing work consistent with § 192.437(a) prior to the filing of this rate case. A May 2014 consultant's report to PG&E states that "at present, PG&E does not have a written plan to identify, test for, and minimize the detrimental effects of stray currents per 49 CFR 192.437 (a) and PHMSA part 192 Guidance."[600] Thus, PG&E was aware that it was not performing work as required by federal regulations.

PG&E did not have a written plan to test for or mitigate stray currents and it appears that PG&E did not routinely perform mitigative action in instances where it became aware of stray currents. PG&E references in testimony a 2012 self-report saying as that it was aware of unprotected pipeline in proximity to electric transmission towers and at risk of AC coupling but had not taken action to mitigate the risk.[601]

ORA in initial testimony did not recommend any disallowance for the $528,000 in 2015 expense[602] for AC Interference, for the following reasons:

PG&E states in testimony that forecast AC interference expense "includes the investigation to identify the locations with a possible AC interference threat and to perform the risk ranking of inspection data."[603] However, PG&E did not provide workpapers substantiating this expense forecast. Without supporting workpapers, PG&E cannot show that its forecast results in just and reasonable rates, however ORA does not recommend a disallowance at this time with the expectation that PG&E will provide workpapers in rebuttal.[604]

However, on rebuttal PG&E explained:

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[599] Ex. ORA-137 (PHMSA Enforcement Guidance Part 192), p. 92.

[600] Ex. PG&E-45, p. A-557 (Exponent *PG&E Gas Transmission & Distribution Corrosion Program Health Assessment*, p. 42).

[601] Ex. PG&E - 1 p.7-28. (Armato/PG&E).

[602] Ex. PG&E-1, Table 7-9, p. 7-32.

[603] PG&E Prepared Testimony, Volume 1 (Peralta), p.7-32.

[604] Ex. ORA-40, p. 14 (Karle/ORA).

> It was PG&E's internal guidance for preparing this rate case proceeding documentation to only develop workpapers and detailed cost calculators for programs with forecasts greater than $1 million.[605]

Based on this updated understanding of PG&E's position on workpapers supporting the 2015 expense forecast in this area, ORA revises its initial recommendation to disallow the $528,000 in expenses as unsupported. ORA's initial testimony noted the lack of workpapers, and PG&E stated none were needed to support its request.

ORA's capital recommendations focused on one capital project, regarding Line 401 (L-401). As ORA noted in testimony, L-401 runs parallel to a 500kV electric transmission line. In workpapers, PG&E states that during the 1993 and 1994 construction of L-401, 60 miles of AC mitigation were installed.[606] PG&E states that the service life of the previous mitigation measures was 20 years, and that installation was completed 19 years ago.[607] PG&E bases cost projections on the assumption that 50% of the original equipment is failing, and forecasts $5.5 million in capital expenditure for 2015 to fund investigation of the state of existing mitigation measures and to replace failing components.[608] [609]

As stated in the workpapers:

> In order to continue to protect the pipeline from AC induction and AC coupling conditions, a study is necessary to determine the condition of the equipment installed, how it is operating, to replace or upgrade anything that does not work adequately, and to install additional equipment to address protection deficiencies. The planned amount of grounding is based on historical protection design of this transmission line and assuming 50% of the original equipment is failing. The life span of the previous mitigation system was designed for 20 years and installation was completed 19 years ago. PG&E has direct examination evidence of degradation of the originally installed AC protection system which has led to the need for this specific project.[610]

[605] Ex. PG&E-40, p. 7-51; 22 RT 2541:24 – 2543:1 (Armato/PG&E).

[606] Ex. PG&E-9 (PG&E Workpapers), Chapter 7, p. WP 7-83.

[607] Ex. PG&E-9 (PG&E Workpapers), Chapter 7, p. WP 7-84.

[608] Ex. PG&E-9 (PG&E Workpapers), Chapter 7, p. WP 7-84.

[609] Ex. ORA-40, p. 15 (Karle/ORA).

[610] Ex. PG&E-9 (PG&E Workpapers), Chapter 7, p. WP 7-84.

Based on the above analysis, ORA observed that "PG&E's failure to initiate a study into the condition of these mitigation measures until fully half of the AC mitigations along a major transmission line have presumably failed does not appear to meet the requirements of federal regulations requiring that operators continually monitor for and mitigate stray currents."[611] PG&E requests costs to replace 30 miles of the initial 60 miles of mitigation, representing that 50%.[612] Due to this clear failure by PG&E to provide AC Interference for L-401 ORA recommended that "the Commission accept PG&E's forecast for inspection, but place a 50% cost cap on funds for mitigation."[613] ORA recommends $5,750,555 in capital expenditures for 2015 Alternating Current (AC) interference mitigation, which accounts for investigation and half of PG&E's mitigation forecast, and which excludes $4,599,177 from PG&E's $10,349,647 capital expenditure forecast.[614] A 50% cost cap that equally shares costs between ratepayers and shareholders reflects a fair outcome based on the need for the project and PG&E's contribution to the problem.

10.4 **DC Interference**

ORA testified that its analysis for DC Interference was identical to that of AC interference and recommends a similar 50% cost cap.[615] ORA recommends $2,024,231 for 2015 Direct Current (DC) interference mitigation which accounts for investigation and half of PG&E's mitigation forecast, and which excludes $527,638 of PG&E's $2,551,869 expense forecast for DC interference mitigation.[616] ORA recommeds $400,893 in capital expenditure forecast for

[611] Ex. ORA-40, p. 15, 16 (Karle/ORA).

[612] 22 RT 2547:27 – 2550:3 (Armato/PG&E); Ex. PG&E-9 (PG&E Workpapers), Chapter 7, p. WP 7-84.

[613] Ex. ORA-40, p. 16 (Karle/ORA).

[614] Ex. ORA-40 (Karle/ORA), p. 2; *see also id.,* Table 7-2, p. 3.

[615] ORA-40, pp. 15-17 (Karle/ORA).

[616] Ex. ORA-40 (Karle/ORA), p. 1; *see also id.,* Table 7-1, p. 2, Table 7-10, p. 17.

2015 DC interference mitigation, which accounts for half of PG&E's mitigation forecast of $801,786 and excludes $400,893 of PG&E's forecast.[617]

10.5 Atmospheric Corrosion

Atmospheric Corrosion can occur on exposed transmission pipes, which cannot be protected by cathodic protection as they are not in contact with soil. According to PG&E's workpapers, the only protection available to inhibit this type of corrosion is adequate coating.[618]

PG&E is forecasting $20.4 million in atmospheric corrosion-related expense for the 2015 TY. The extent to which the forecast consists of incremental spending is unclear, given PG&E's 2012 redesign of major work categories. As elsewhere in this report ORA's position relating to deferred corrosion control maintenance that ratepayers should not be asked to bear the full cost of performing such work. ORA applied the same methodology to develop a forecast for atmospheric corrosion as was applied to AC and DC mitigation.

ORA recommends $16,143,948 in 2015 expenses for atmospheric corrosion, which accounts for investigation and half of PG&E's mitigation forecast, and which excludes $4,293,098 of PG&E's $20,437,046 forecast.[619] The adjustments recommended by ORA were developed using the ratio of inspection to mitigation (approximately 58% investigation, 42% mitigation) in PG&E's expense forecast as shown in PG&E's workpapers.[620] ORA applied this ratio to each expense line item to determine the breakdown of investigation to mitigation forecast. ORA then added 50% of the forecast mitigation to PG&E's inspection forecast in order to develop an appropriate cost cap.[621]

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[617] Ex. ORA-40 (Karle/ORA), p. 2; *see also id.,* Table 7-2, p. 3.

[618] PG&E-1, p. 7-47 (ORA/Armato).

[619] Ex. ORA-40 (Karle/ORA), p. 1; *see also id.,* Table 7-1, p. 2; Table 7-12, p. 20.

[620] Ex. PG&E-9, PG&E Workpapers, Chapter 7, p. WP 7-49.

[621] Ex. ORA-40 (Karle/ORA),

10.6 **Cathodic Protection Systems**

10.7 **Coupon Test Stations**

10.8 **Internal Corrosion**

10.9 **CP Rectifier, Monitoring, Resurveying, Troubleshooting**

10.10 **Corrosion Investigations**

10.11 **Close Interval Survey**

11 GAS TRANSMISSION SYSTEM OPERATIONS AND MAINTENANCE ACTIVITIES

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12.8.1 Stipulation Between PG&E and ORA

The Joint Stiulation-3 between ORA and PG&E, where PG&E accepts ORA's forecast of $8.9 million for TY 2015 is reasonable and should be adopted. ORA presented its recommendations in Ex. ORA-42.

12.8.2 Comments

12.9 Building Management Expenditures

13 GAS SYSTEM OPERATIONS

13.1 Overview and Summary

13.2 Gas Station Operations Staff

13.3 Normal Operating Pressure Reductions

13.4 Network Investment Plans

13.5 New Business

13.6 Capacity Projects

13.7 Allocation of Storage Assets to Pipeline Land Balancing

13.8 Electricity Costs for Gas Compressor Operations

13.8.1 Stipulation Between PG&E and ORA

The Joint Stipulation-3 between ORA and PG&E, where PG&E accepts ORA's forecast of $18,241 thousand for TY 2015 is reasonable and should be adopted. ORA presented its recommendations in Ex. ORA-56.

13.8.2 Comments

13.9 Recovery of Greenhouse Gas Compliance Instrument Costs

13.9.1 Stipulation Between PG&E and ORA

The Joint Stipulation-3 between ORA and PG&E, where PG&E accepts ORA's forecast of $3,088 thousand for TY 2015 is reasonable and should be adopted. ORA presented its recommendations in Ex. ORA-56.

13.9.2 Comments

13.10 Gill Ranch Storage's Proposal for Daily Balancing

14 INFORMATION TECHNOLOGY

14.1 Stipulation Between PG&E, ORA and TURN

The Joint Stipulation-4 between ORA, PG&E, and TURN should be adopted. ORA presented its recommendations in Ex. ORA-15. Under the stipulation, PG&E would receive for TY 2015 $22.515 million for capital projects and $14.660 million for expense projects.

14.2 Comments

> However, for 2013, ORA recommends the adoption of 2013 recorded capital expenditures of $5.599 million, rather than PG&E's forecast of $14.973 million.[622]

15 REPORTING REQUIREMENTS AND PROGRAM MANAGEMENT

15.1 Stipulation Between PG&E and ORA

The Joint Stipulation-3 between ORA and PG&E should be adopted. ORA presented its recommendations in Ex. ORA-13. Under the stipulation ORA and PG&E recommend a Commission-led workshop to review reporting requirements, and that the requirements should also align with the GRC OIR decision.

15.2 Comments

15.3 Stipulation Between Calpine and PG&E

15.4 Comments

16 REVENUE REQUIREMENT ISSUES

16.1 Computational Matters

16.2 Taxes: NOL and Bonus Depreciation

16.2.1 Stipulation Between PG&E and ORA

Joint Stipulation-2 between ORA and PG&E is reasonable and should be adopted.

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[622] Ex. ORA-15 (Oh/ORA), pp. 4-5.

16.2.2 Comments

16.3 Cost Recovery Issues

16.3.1 Transmission Revenue Balancing Account

16.3.2 Transmission Integrity Management Program Balancing Account

16.4 Post Test Year Ratemaking (PTYR)

16.4.1 Stipulation Between PG&E and ORA

Joint Stipulation-3 between ORA and PG&E should be adopted. The stipulation is based on Ex. ORA-22 on Post Test Year ratemaking and and resolves various inputs associated with PG&E's programs across chapters.

16.4.2 Comments

16.5 Rate Base Depreciation

16.5.1 Stipulation Between PG&E and TURN

16.5.2 Comments

17 RATE ISSUES

17.1 Throughput Forecasts

17.1.1 Stipulation Between PG&E and ORA

Joint Stipulation-3 between ORA and PG&E should be adopted. In the stipulation, PG&E agrees with ORA's forecast as presented in Ex. ORA-43.

17.1.2 Comments

17.2 Cost Allocation and Rate Design

17.2.1 Backbone Rate Design

17.2.1.1 Equalization of the Baja and Redwood Path Rates for Core and Noncore

ORA opposes PG&E's proposal to equalize the Baja and Redwood Path Rates. This proposal increases costs to core customers who buy long-term capacity rather than gas at the city gate. Core customers have long paid specifc rates for each path, and now that the Redwood Path costs are below Baja Path, Redwood Path customers would essentially be subsidizing Baja Path customers.[623] PG&E's proposal, in fact, may lead to market distortions since this proposal would incentivize shippers to bring gas in from the cheapest source, while abandoning cost-causation principals for transporting that gas within California.[624] PG&E itself states that the Baja Path has a higher revenue requirement than the Redwood Path.[625] Furthermore, PG&E has not demonstrated that Citygate prices would actually decline under their proposal.[626]

For these reasons, the Commission should reject PG&E's proposal to equalize the Redwood and Baja Paths.

[623] Ex. ORA-41 (Sabino/ORA), pp. 58-62.

[624] Ex. ORA-41 (Sabino/ORA), p. 62.

[625] Ex. PG&E-2 (Christopher/PG&E), p. 10-21.

[626] Ex. ORA-41 (Sabino/ORA), pp. 61-62.

17.2.1.2 Backbone Load Factor Calculation

17.2.1.3 Backbone Capacity for the Baja Path and the Redwood Path

17.2.2 Local Transmission Cost Allocation

17.2.2.1 PG&E's Proposed Local Transmission Cost Allocation Retains the Same Design As Has Been Used Throughout the Gas Accords and Is Reasonable

PG&E is proposing to retain its current allocation of local transmission costs between core and noncore customers of 67%/33% based on cold year peak month throughput of these customer classes.[627] PG&E has utilized this same allocation methodology based on cold year peak month throughput has been used by PG&E since D.92-12-058.[628] ORA believes PG&E has met its initial burden of proof of showing that this long-standing methodology results in just and reasonable local transmission rates for all customers, assuming it applies to a just and reasonable revenue requirement.

17.2.2.2 Calpine/IS Does Not Show That Its Proposed Allocation Is Preferable To PG&E's Proposed Allocation

Calpine/IS proposes to change the allocation to a 74%/26% to core and noncore customers on the basis of cold winter peak day throughput, which Calpine/IS argues "better represents the design basis for local transmission facilities."[629] The impact on local transmsion core customers solely due to adopting Mr. Beach's proposed changed core/noncore allocation of 74%/26% core/noncore instead of the current 67%/33% allocation is huge by itself, a 10.4% increase of costs allocable to core, and a 21.2% decrease in costs allocable to noncore customers.[630]

Although Calpine/IS Mr. Beach states is "concerned about the very large noncore rate increases which PG&E has proposed in this rate case,"[631] and testifies that "[t]he magnitude of

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[627] 27 RT 3617:9 – 3618:13 (Calpine-IS/Beach).

[628] 27 RT 3618:24 - 3619:1 (Calpine-IS/Beach).

[629] 3619:2-9; Ex. Calpine/IS-2 Table 1(Beach Errata Testimony) , Ex. Calpine/IS-1 (Beach Testimony)

[630] Core increase = [(74-67)/67]; Noncore Decrease = [(33-26)/33]. ORA-46 (Sabino Ch. 20 Errata), p.2; 27 RT 3620:19 – 3621:12.

[631] Ex. Calpine/IS-1, p. 6.

the increases in the local transmission costs which PG&E is proposing, particularly for noncore customers, also justifies a new look at the allocation of these costs,"[632] the rate increases for core customers for local transmission service are much bigger than the increases for noncore for local transmission service, on a percentage and absolute basis even if PG&E's proposal to maintain the current allocation is adopted, as Mr. Beach's own numbers in Table 2[633] clearly show. PG&E's proposed 2015 core retail rate of $1.959/Dth, compared with the 2014 rate of $0.680/Dth, is a 188% increase or $1.279/Dth, whereas the proposed noncore 2015 rate of $0.875/Dth, compared with the 2014 rate of $0.332/dth is a 164% increase or $0.543/Dth. Mr. Beach's allocation proposal then greatly increases the different size rate increases in favor of noncore customers. Under Mr. Beach's allocation proposal, the 2015 core retail rate of $2.149/Dth is a 216% increase, or $1.469/Dth over the 2014 rate, while the 2015 noncore rate of $0.701 is a 111% increase, or $0.369/Dth, over the 2014 rate, almost twice as much a percentage rate increase in 2015 for the core than noncore. The rate impact on 2015 core rates solely due to Mr. Beach's proposal compared to PG&E's would be a 9.7% increase or $0.190/Dth, while the impact of Mr. Beach's proposal on 2015 noncore rates would be a 19.9% <u>decrease</u> or $0.174/Dth.[634]

Calpine/IS notes the large rate increase caused by PG&E's safety improvements, combined with the alleged increased safety benefit to core customers than non-core customers based on PG&E prioritizing safety improvements on pipes in populated areas that Calpine/IS provide more benefits to core than noncore customers, motivates its proposal to change local transmission allocation.[635] But the Commission has recently concluded that safety costs benefit customer classes equally and should not justify a change in cost allocation. In San Diego Gas and Electric Company's ("SDG&E's") and Southern California Gas Company's (SCG's)

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[632] Ex. Calpine/IS-1, p. 8 (emphasis added).

[633] Ex. Calpine/IS-1, p. 12.

[634] Ex. ORA-46, pp. 2-3, Ex. Table 2, p. 4; *see* 27 RT 3623:4 – 3629:23 (Calpine/IS / Beach)

[635] See Calpine/IS-1, pp. i, 5, 7 lines 8 & 28; see also p. 21, p. 22."PG&E reports that more than one million citizens live or work within the Potential Impact Radius of its gas transmission pipelines. **These** core ratepayers who live and work in proximity to transmission pipelines will be the direct beneficiaries of the safety improvements to the local transmission system, as they will bear fewer risks from pipeline failures." Calpine/IS-1, p. 10 (Emphasis added).

Triennial Cost Allocation Proceeding (TCAP), D. 14-06-007,[636] in which the Commission explicitly rejected a portion of a contested settlement that proposed changing current allocation factors for gas Pipeline Safety Enhancement Program (PSEP) costs and dramatically increasing the allocation assigned to core customers on the basis that the new safety expenditures benefitted core customers in a higher proportion than other gas spending. The Commission determined in Conclusion of Law 30 that "[t]he existing cost allocation methodology is reasonable for the costs of Safety Enhancement because these costs are necessary to safely and reliably supply natural gas to existing customers in the same manner as the existing system serves customers."[637] The Commission rejected the proposed modifications to existing cost allocation methodology on SCG's and SDG&E's system that were specifically directed at Safety Enhancement Costs and ordered that "Safety Enhancement costs will be allocated consistent with the existing cost allocation and rate design for the companies."[638] The Commision must reject the Calpine/IS proposal, and the propsosal of the Northern California Generation Coalition (NCGC)[639] for the same reasons.

The other reasons offered by Mr. Beach do not outweigh the above considerations, but are not persuasive anyway. Design standard is not the sole method to allocate customer costs. Because core customers purchase gas from PG&E while noncore customers generally purchase gas independently from suppliers other than PG&E, local transmission costs are a bigger proportion of noncore customers PG&E cost than they are for core customers, and thus an increase to such rates will raise their overall rates to PG&E higher than the increase to overall rates of the core, but this is not an apples-to-apples comparison. The Commission should retain the current cost allocation.

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[636] D.14-06-007, *Decision Implementing a Safety Enhancement Plan and Approval Process for San Diego Gas and Electric Company and Southern California Gas Company; Denying the Proposed Cost Allocation for Safety Enhancement Costs; and Adopting a Ratemaking Settlement*, (June 12, 2014), in A.11-11-002. (TCAP Decision.) See Ex. ORA-169 Attachment A.

[637] Id., Conclusion of Law. No. 30, p. 59 (

[638] Id., Ordering Paragraph No. 9, p. 61. The Commission applied SDG&E's/SCG's core/non-core/backbone allocation factor of 53.9/43.8/2.3 to PSEP spending. See ORA Reply Brief in A.11-11-002, p. 1. Ex. ORA-169, Attachment B.

[639] *See* Ex. NCGC-1,pp. 11 -12 (NCGC/Falcon).

17.2.3 Storage Rate Design

17.2.3.1 Storage Capacity

17.2.3.2 Allocation of Storage Costs

17.2.3.3 Core Injection and Withdrawal

17.2.4 Transmission Level Customer Access Charges

17.2.5 Electric Generation Rate Design

17.2.6 Commercial Energy's Proposal to Modify the Noncore Customer Class Definition

18 CORE GAS SUPPLY

18.1 **PG&E Core Gas Supply Proposals**

18.1.1 Core Intrastate Pipeline Capacity

18.1.2 PG&E Firm Storage Capacity

18.1.3 Adjustments to 1-Day-in 10-Year Core Capacity Planning Standard

18.1.4 Changes to Core Procurement Incentive Mechanism

18.1.5 Pipeline Capacity Allocation Methodology

18.1.6 Incremental Storage Capacity Allocation

18.2 **Core Transport Agent Issues**

18.2.1 Core Load Forecast Model

18.2.2 CTA Procurement of Intrastate Pipeline Capacity and Gas Storage Capacity

18.2.3 Modifying The Firm Winter Capacity Requirement

18.2.4 Operational and Billing Issues

19 PROPOSALS FOR PROGRAMS DIRECTED TOWARD SMALL AND MEDIUM SIZED BUSINESSES

Respectfully submitted,

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